Delta electricity

18 February 2021

Ms Anna Collyer
Chair
Australian Energy Market Commission
Sydney

Dear Ms Collyer,

RE: RESERVE SERVICES IN THE NATIONAL ELECTRICITY MARKET DIRECTIONS PAPER

Delta Electricity welcomes the opportunity to provide detailed comment on the AEMC's Reserve Services in the National Electricity Market Directions Paper in recognition of the strains increasingly appearing in the NEM – as evidenced by AEMO interventions - and the need to take steps well ahead of 2025 to address these issues to ensure Australian households and businesses continue to enjoy an affordable and reliable supply of electricity.

Delta Electricity has been operating in the NEM since its inception and owns and operates the 1320MW Vales Point Power Station in NSW, has a 150MW PPA with the Darlington Point Solar Farm, and is an energy retailer to large industrial customers. Delta's response to the Directions Paper is in four parts:

- Delta Electricity letter to AEMC Chair (this letter);
- AEMC Reserve Services in the NEM Directions Paper – Delta Response (in presentation form);
- Delta Electricity response to Directions Paper questions; and
- Delta Electricity Rule Changes – Frequently Asked Questions (explains aspects of Delta's Unit Commitment for Reliability and Security Rule Change and Delta's Ramping Services Rule Change).

The materials presented are necessarily complex and Delta has chosen to present its position and accompanying analysis in the form of a PowerPoint Presentation. I have set out below a summary of Delta's position.

Background

From Delta's perspective, the Directions Paper does not adequately respond to the existing and projected market needs for reserve and ramping services. Upfront the Direction Paper asserts that the current arrangements in the NEM are sufficient to meet expected changes in demand and supply in the market, but in doing so it fails to acknowledge the large number of statements from the market operator. AEMO is increasingly required to intervene in the market to ensure system security. Several concerns expressed by AEMO have been echoed by the Energy Security Board (ESB). These statements are referenced below.

The effect of this stance by the AEMC is that it arbitrarily limits consideration of NEM issues to unexpected changes and uncertainty. That is, the AEMC's approach excludes consideration of whether expected changes in demand and supply in the NEM require action to allow such changes to be managed without inefficient and costly interventions by AEMO. Delta submits that this apparent arbitrary decision is inconsistent with the analysis presented by AEMO in its Renewable Integration Study

Sunset Power International Pty Ltd t/as Delta Electricity ABN 75 162 696 335 ACN 162 696 335
SYDNEY OFFICE Suite 5.01, 580 George Street, Sydney NSW 2000 PO Box 7285 Mannering Park NSW 2259
Telephone 02 4352 6111 Facsimile 02 4352 6460 www.de.com.au

Appendix C: Managing variability and uncertainty" in which AEMO concluded (page 45; emphasis added):

> *"The increase in variability and uncertainty in net demand, projected out to 2025, increases the demand for system flexibility to cover **forecast and unforecast ramps**".*

Additionally, this apparent arbitrary decision by the AEMC to exclude expected changes from its consideration has been taken despite clear signals that the current market arrangements are strained, with the reasonable conclusion (based on projections of variable renewable energy (VRE) entering the NEM over coming years) that the current arrangements are no longer fit-for-purpose. In fact, State Government programs, such as that adopted through legislation by the NSW Government last year, will shift the level of intermittent generation entering the NEM from the ISP's central scenario levels to, or beyond, its significantly higher "Step Change" scenario. Delta is therefore somewhat perplexed as to why the AEMC did not acknowledge the resultant increased risks to the NEM and the consequential greater urgency to respond through immediate steps to "future proof" the NEM.

Experience in South Australia clearly demonstrates the inter-related issues caused by high levels of intermittent generation (including household solar PV) forcing thermal generators to de-commit in response to low (or negative) prices, with the result that AEMO is then forced to intervene to manage operational demand and ensure there are sufficient essential system services being provided to maintain system security. The adverse impact of this inefficient intervention by AEMO is twofold:

- (i) curtailing intermittent generation, creating opportunity costs for consumers and a real cost for the owners of these assets; and
- (ii) the actual costs incurred from AEMO's intervention.

AEMO set out its concerns in its 2020 Renewable Integration Study as to the implications of the increasing level of interventions it is being required to undertake to maintain system security in response to high levels of intermittent generation (including household solar PV) and the consequential impact on traditional thermal synchronous generators and the essential system services that they provide. AEMO clearly flagged these Interventions will continue to increase in frequency and an increasing number of NEM jurisdictions (page 28; emphasis added):

> "*While intervention mechanisms have always been a part of operating a secure NEM, historically their use has been low, with intervention used as a last resort to manage specific issues on the grid. An intervention should only arise if there is a failure in the market to deliver the necessary power system outcome. **Frequent interventions being needed for the same issue would imply an enduring market failure**.*
>
> *"As Section 2.3 outlines, however, **intervention is now commonplace in parts of the NEM and is expected to be required more frequently in more NEM regions over the next five years**".*

And AEMO particularly noted in its Renewable Integration Study (RIS) (page 33; emphasis added):

> "*Based on the current market framework and projected resources mix of the draft 2020 ISP Central Scenario, **the requirement for interventions will increase across the NEM out to 2025 as instantaneous penetrations of wind and solar generation grow***".

The ESB highlighted in its latest "Health of the NEM" report released in January 2021 that System Security is the major risk with the operation of the NEM (page 5; emphasis added):

*"**Security remains the most concerning issue in the NEM**. Maintaining the electricity system within the required parameters for frequency, voltage, inertia and system strength becomes harder as variable renewable generation increases its presence in the NEM.... Wind and solar powered generation resources are non-synchronous"* and do not have the same technical characteristics as thermal and hydro power generation.

Against this background Delta believes the NEM is currently **not** fit-for-purpose and cannot understand why the AEMC has taken a position in the Directions Paper that is at odds with the positions of both AEMO and the ESB as set out above.

Ramping: Consistently Identified by AEMO as a Key Challenge Requiring New Responses

Analysis of AEMO documents demonstrate that since at least 2018, AEMO has identified an increasing ramping requirement as a key challenge to reliability and security in the NEM. The implications of this increasing ramping requirement were particularly explored by AEMO in its 2020 RIS. This analysis demonstrates that the magnitude of ramps in the NEM is increasing – and will continue to increase further – and that whereas ramps have been previously predictable, going forward ramps will be increasingly driven by movements in intermittent generation supply and, therefore, will be subject to uncertainty.

The key insights presented by AEMO were (AEMO's RIS Appendix C, page 14, emphasis added):

- *"The magnitude of ramps in the NEM is increasing. Across the NEM, the largest historical 5-minute downward VRE ramp was -815 MW. This is projected to increase to -1,416 MW by 2025.*

- *The frequency of large ramps is increasing. By 2025, a 1-hour ramp across the NEM that is larger than 2.6 GW (10% of VRE capacity in 2025) is projected to occur on 54 different days across the year, outside of predictable sunrise and sunset hours."*

- *"VRE will be a significant driver of ramps in net demand by 2025:*
    - *In 2018, the top 1% of hourly net demand ramps (that is, ramps > 3.4 GW) were driven by movements in underlying demand, which is largely predictable.*
    - *By 2025, the top 1% of hourly new demand ramps (that is, ramps > 5.1 GW) **will be driven predominantly by movements in VRE, which are typically more subject to uncertainty**. "*

It is noted that AEMO's analysis in the RIS is based on the Central Scenario in its Integrated System Plan (ISP), with AEMO noting (RIS, page 18):

"The ISP's Central Scenario renewable generation build forecast is conservative in comparison to the Step Change scenario. If the generation build in the NEM develops according to the Step Change scenario, the observations in this study would be accelerated".

As noted above, State Government initiatives to accelerate the deployment of intermittent generation in the NEM, together with the Clean Energy Regulator's latest projections of an additional 3,200MW per annum build of small scale (rooftop) solar over the next four years[1], will shift the level of intermittent generation entering the NEM from the ISP's Central scenario levels to, or beyond, its significantly higher "Step Change" scenario. Delta therefore believes that the conclusions set out above from AEMO's RIS

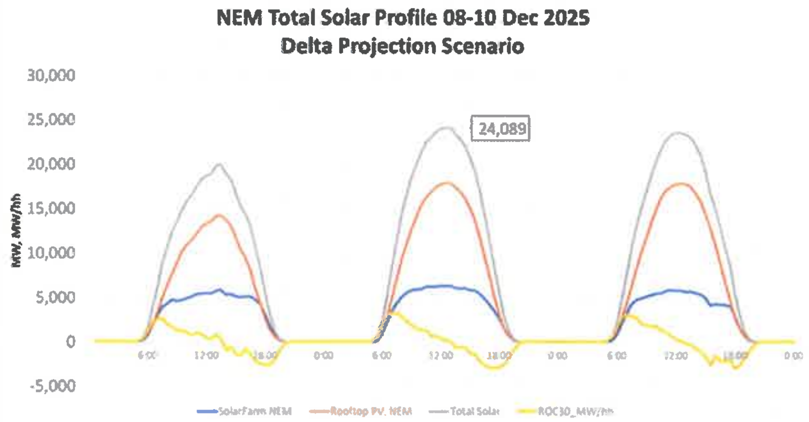
[1] Clean Energy Regulator 'Quarterly Carbon Market Report' September 2020, page 4

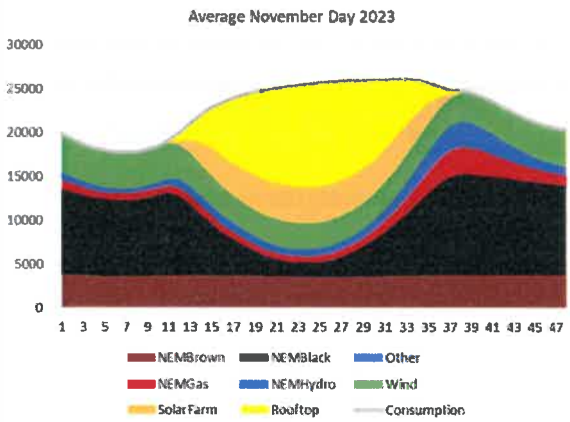
analysis are now conservative, and that this reinforces the need for urgent action to address these issues highlighted by AEMO.

Analysis of Operating Reserve and Ramping

Delta has carried out analysis showing that managing the solar profile (let alone the added variability in wind), especially the morning and evening solar ramping, will be a dominant feature in the operation of the near future NEM. This result assumes levels of solar generation (both rooftop and grid-scale solar farms) consistent with recent projections by the CER and AEMO's RIS "Step Change" scenario (Figure 1). The charts are only extrapolations of current dispatch profiles, and these profiles may not be operationally feasible, but they do highlight the potential implications for NEM operations under the announced targets for new wind and solar. What the solar shape does not show is the additional variability in net demand that will be added by wind variability and consumption changes.

Figure 1 - Wind and solar projections based on Delta Projection scenario





1. Ramping

The chart on the left in Figure 1 shows daily ramping-in and ramping-out of up to nearly 24,000MW by 2025. To balance supply with demand, AEMO needs to ramp-out then ramp-back in up to 24,000 MW of capacity from synchronous generators, principally hydro and conventional thermal generators. Every day. For comparison, the 2020 NEM average and maximum demands were 21,408MW and 35,440MW respectively so 24,000MW represents more than NEM average demand and 67.7% of NEM maximum demand, consistent with AEMO's conclusions (below). Managing this daily pattern requires more than the current arrangements for operating reserve – it needs a dedicated approach – a dedicated service.

AEMO's RIS, page 19 and Figure 5: *"This figure* [Figure 5] *highlights significant forecast growth in the maximum potential instantaneous penetration of wind and solar, from just under 50% in 2019 to well over 75% at times under the 2025 Central generation build and up to 100% under the Step Change generation build."*

The issue of considering standby (decommitted) capability and planning ahead to ensure that ramping capability is committed ahead of when it is needed is a theme identified by both the ESB and AEMO in the statements below (emphasis added):

ESB The Health of the NEM 2020 page 29:
"***Key Challenges identified in Stage 1 of the Renewable Integration Study ...***

The magnitude of peak ramps (upward/downward fluctuations in supply/demand) is forecast to increase by 50% over the next five years as a result of increasing wind and solar penetration. Operators need to ensure there is adequate system flexibility to cover increased variability across all times.

There is a limit to the accuracy of deterministic forecasts of expected ramps, even using current best practice approaches. Forecasting limitations increase uncertainty and the need for greater ramping reserves.

Ensuring sufficient flexible system resources are available to enable increased variability at times of high wind and solar penetration will become increasingly challenging. ***Times characterised by low interconnector headroom (spare capacity) or 'cold' offline plant will be particularly difficult to manage."***

AEMO RIS page 59: "To accommodate the transformation to a system dominated by VRE, ***a range of flexible resources must be utilised and planned ahead of time****, so the right mix of resources is available when needed,* ***to meet ramping requirements that vary across different timescales****."*

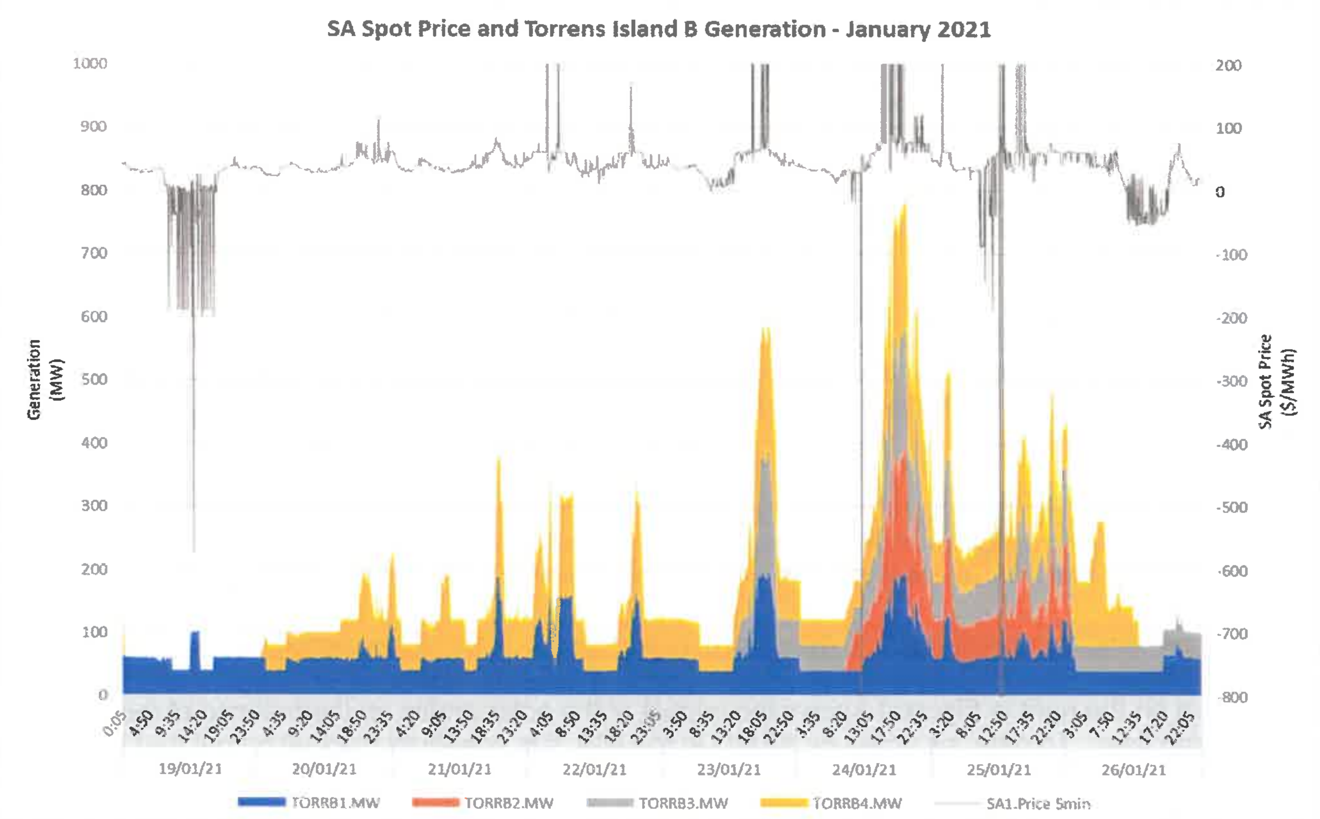
<u>2. More periodic decommitments of synchronous generators leading to a deficit of operating reserves</u>

The chart on the right in Figure 1 shows the impact of the solar profile on the balance of the NEM's generation fleet. To date, as noted by AEMO in the RIS, it is coal-fired thermal output that has primarily been displaced by new solar generation, but such units cannot operate at levels below about 30-54% of their capacity (without very costly diesel auxiliary firing). High levels of VRE, in particular, solar, are already leading to an increase in frequency of low/negative price in the middle of the solar day:

<u>AEMO's QED Q4 2020 p12:</u> *"Negative wholesale electricity prices - During Q4 2020, negative and zero spot prices occurred in 7% of all trading intervals, surpassing the previous record set in Q3 2020 (4.6%), with calendar year 2020 averaging 4.4% compared to 1.7% in 2019. Negative spot prices were most prevalent in South Australia and Victoria, with both states reaching record quarterly levels. South Australia's spot prices were negative 17% of the time during Q4 2020, exceeding the previous quarterly of 10%, while Victoria reached a new record of 10%."*

This price trend will initially lead to temporary or periodic decommitment of conventional thermal generation units. South Australia provides a clear example of how conventional thermal plant will operate in a market with high VRE. Both Torrens Island power stations have gas fired boilers and similar operational limitations as coal- fired plant. These units have minimum loads and restart times that vary depending on their time out of service. As shown in figure 2, in a sample week in January 2021, Torrens Island B units are economically removed from service during low priced periods and returned to capture higher prices. The advance notice for Torrens Island unit to commit is understood to be 12 hours or longer. Pre-dispatch price signals in the market will not incentivise unit commitment (due to high start-up costs) unless prices are sufficiently high and certain. The commitment of a large thermal unit will reduce the actual price, and this gives rise to even more risk that a commitment decision may not deliver a return, particular in the lower demand, lower energy price periods. It is important to note that Torrens Island plant, like the fast start SA gas peakers, is subject to AEMO directions to maintain system security and reliability.

Figure 2 - Commitment profiles for conventional plant with highly variable spot prices



What Changes Are Required

The analysis demonstrates that the current NEM arrangements will simply not be able to manage even expected changes in demand and supply because of increases in:

(i) the magnitude of daily ramps, driven principally by the regular (and, therefore, expected) daily pattern with the supply of electricity from large scale solar, household solar PV and wind variability;

(ii) the duration of these expected daily ramps. The daily ramps will be larger and longer – and harder to manage, requiring AEMO to have access to the full suite of available resources over a number of timeframes (including day ahead); and

(iii) the frequency of decommitment of large synchronous generators in response to VRE-induced low/negative prices, removing from the NEM the operating reserve, ramping and other essential system services those generators would otherwise provide.

In order to address both the expected changes and unexpected changes caused by increased intermittent generation in the NEM, and the associated reduction in availability of system services from thermal synchronous generators that have traditionally supplied these services free of charge or as a "by-product" of the energy they generated and supplied to the NEM, separate market-based reserve and ramping arrangements are required.

Delta considers that operating reserve and ramping mechanisms are complementary and ideally should be designed to operate together effectively to ensure that AEMO can largely avoid directing the market. This approach is technologically neutral and would prove particularly supportive of demand response and batteries. It would also incentivise innovation in operation and investment. This type of approach has been supported by AEMO and the ESB, with both entities identifying the appropriate response (emphasis added):

- AEMO, Renewable Integration Study report, page 59: "*To accommodate the transformation to a system dominated by VRE, a range of flexible resources must be utilised and planned ahead of time, so the right mix of resources is available when needed, to meet ramping requirements that vary across different timescales*".

- AEMO, Renewable Integration Study Appendix C: Managing variability and uncertainty, page 46: "*To operate the system successfully, flexibility must be able to be scheduled in the right direction at the right time. Flexibility must be harnessed in all parts of the power system by enhancing traditional sources, as well as embracing emerging sources*".

- ESB, System Services and Ahead Markets, pages 14-15: "Operating reserve is a product proposed to ensure there is adequate spare dispatchable capacity in the system to provide flexibility in real-time. **The RIS has shown that variability in the study year of 2025 is expected to be significantly higher than now and, combined with the inherent uncertainties in forecasts, there is a need for additional reserve in the system in order to respond to unexpected changes in supply and demand over a range of timescales.** ....

  "..........Additional reserve products, such as **flexible ramping products** and imbalance services, have also been introduced in some markets (such as California) to adapt to the increased variability and uncertainty by **ensuring sufficient dispatchable reserves are committed to provide the flexibility in real-time.**

  "The NEM differs from many other markets globally in that it relies on participants managing their own portfolios to provide additional reserve *beyond* the current dispatch interval, without explicitly remunerating such provision. Individual participants typically leave spare headroom in their portfolio to protect themselves against unexpected changes (such as a plant outage) that would leave them short against their contracted position. This decentralised and voluntary approach assumes that all participants collectively have the right incentive to provide the efficient reserve level with the appropriate flexibility to manage system changes. In a system with an abundance of dispatchable capacity and with uncertainty mainly due to load forecast error and contingencies, this approach has been acceptable without significant system operator intervention. However, **with increasing variability and uncertainty in supply and demand and with pressure on synchronous capacity that provides the headroom, this approach may not be sustainable in the future**. Without enough operating reserve, the system might not be secure or reliable when the supply-demand balance changes unexpectedly. With increasing variability and uncertainty, there could be more instances where there is a forecast of insufficient reserve to protect against the largest contingency, forecast uncertainty or the need to increase supply over multiple dispatch intervals (ramping need), where AEMO will issue a lack of reserve notice**. In the absence of explicitly remunerating participants for additional reserve provision, there might not be an adequate market response, forcing AEMO to intervene through RERT or direction in the market, which could be costly to consumers**.

  "The introduction of explicit operating reserve services addresses this."

It was on the basis of its own experiences in the market, and guided by the analysis presented by AEMO and the ESB, that Delta submitted two rule change proposals to the AEMC on 4 June 2020:

- 'Capacity Commitment Mechanism for Operational Reserve and Other System Security Services': A Day-ahead Capacity Commitment Mechanism; and
- 'New 30-minute FCAS Raise and Lower Services': A New 30-minute Ramping Services Mechanism.

Regrettably the AEMC has made an arbitrary decision to split consideration of these two inter-related rule changes, with the result that only the second rule change is considered as part of the Directions Paper. This has had the effect of separating out consideration of the capacity commitment mechanism and thus denying appropriate consideration of a day-ahead commitment mechanism for the provision of operating reserve and other essential services. Delta particularly notes in this context that AEMO advised the AEMC in its letter[2] commenting on Delta's Capacity Commitment Mechanism Rule Change proposal that (emphasis added):

- *".......AEMO considers the overall concept – that Generators need to be paid a supplementary, out-of-market, payment for commitment and minimum generation to provide system services is appropriate and **should be prioritised**"*.

It is understood that there is no general support for a formal day-ahead market in which generating unit commitment is locked in advance and aligned with financial contracts leaving only intra-day supply/demand variations to be priced. Delta's proposals do not take away generator self-commitment but obviously there would be penalties applied should a generating unit scheduled to commit before the dispatch day not be able to provide the contracted reserve.

What is Delta Proposing

Delta's rule change proposals seek to address the issues with the operation of the NEM that are already being seen in terms of increased interventions by AEMO to ensure system security and reliability:

- a market-based solution for AEMO to bring standby reserve capability to the market in a timely manner; and
- a 30-minute Ramping FCAS service to meet the separate, distinct challenge in the market driven by increasing levels of intermittent generation, and especially solar (both large scale and household solar PV), that are increasingly dominating daily operations by AEMO.

The accompanying presentation sets out the detail of these two proposed rule changes. The combination of Delta's two proposals would:

- address the decision timeframe in the alternative options presented by the AEMC in its Directions Paper, with the AEMC's limited commitment decision timeframe necessarily limiting the resources available to AEMO;
- address the pressing need to significantly reduce AEMO Interventions, and "future proof" the NEM ahead of further increases in VRE penetration that will increase the projection of VRE penetration from the ISP Central Scenario to the Step Change scenario;
- deliver a technology neutral market-based mechanism that will incentivise economic provision of operating reserves for reliability, system security and ramping.
- incentivise investment in new technologies; and
- significantly reduce costs to consumers and VRE asset owners as the inefficiencies of interventions by AEMO will be replaced with the competitive provision of essential system services.

---

[2] AEMO Submission to AEMC ERC0290 13 August 2020 page 16

Conclusion

In 2020, the total cost involved with AEMO directing South Australian thermal generators on for system strength was $49 Million, or $4.45/MWh (source: AEMO Quarterly Dynamics Q4 2020 report, page 26). If a similar level of directions were required over coming years across all NEM jurisdictions because of a step change in the level of intermittent generation in the NEM, the NEM-wide equivalent cost of such inefficient intervention would be around $800 million annually (based on the assumption that SA accounts for around 6% of the NEM operational demand). That is today's cost. Looking forward this can only increase unless the market delivers the required services that can negate the need for interventions.

This $800 million per annum cost figure has been calculated for illustrative purposes only. However, it serves to highlight:

- the potential negative impact of increasing levels of inefficient interventions due to the current NEM arrangements not being fit-for-purpose; and
- the failure to act by putting in place a market-based mechanism for system services operating alongside the current energy only market will prove to be very expensive for consumers, and these costs will inevitably go higher.

The system is straining under pressure from the increasing VRE in the NEM and needs to be fixed as a priority. The best time to act to address a foreseeable problem is ahead of the event, with market participants then able to adjust their operations appropriately. It is important for energy market bodies to get ahead of the curve and take critical initial steps to future proof the NEM that will flow into the Post 2025 NEM Design.

Delta strongly endorses the following position presented by the ESB in its April 2020 report, "System Services and Ahead Markets" (page 42; emphasis added):

> *"Current operations and identifiable trends ....highlight that leaving the market design unchanged is unlikely to produce the most efficient results and may result in unacceptable risk to the secure and reliable operation of the system.* ***The system is transitioning to one where the provision of energy no longer leads to provision of system services without explicitly valuing, procuring and scheduling these services****. Increasing complexity in the market with distributed resources, changing consumer behaviours, and changing technologies introduces additional uncertainty and variability.* ***The market design needs to keep pace with this change and be able to accommodate more changes in the future. Without reforming the market design, regular out-of-market interventions and constraints will be required and the transition will continue to progress in a disorderly, uncoordinated and costly way".***

Delta therefore submits that the AEMC reconsider the approach it has adopted in its Directions Paper and proposes its two rule change requests be linked together and established as the foundation on which the NEM delivers affordable and reliable electricity for residential and business consumers during this period of transition.

Yours sincerely,

Anthony Callan
Executive Manager Marketing

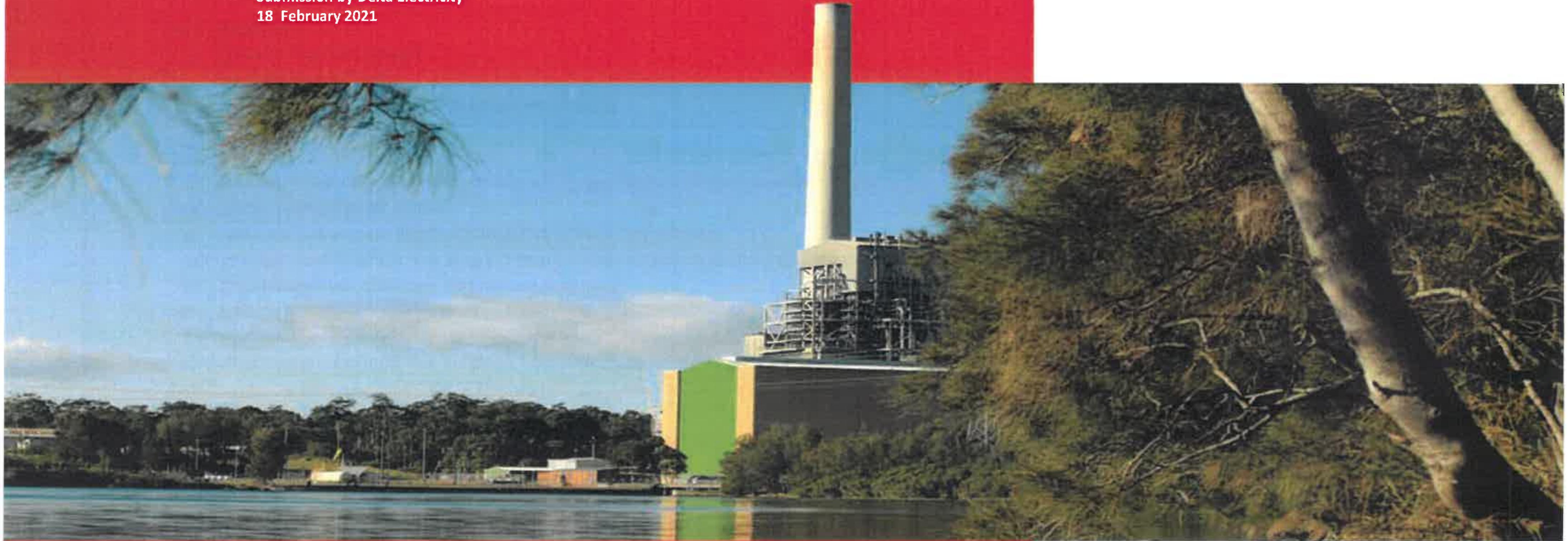
Attachments:

- AEMC Reserve Services in the NEM Directions Paper – Delta Response (in presentation form)
- Delta Electricity response to Directions Paper questions.
- Delta Electricity Rule Changes – Frequently Asked Questions.

AEMC Directions Paper
Reserve Services in the NEM

Delta Electricity Response

Submission by Delta Electricity
18 February 2021



Delta
electricity

Table of Contents

Delta electricity

Executive Summary I

Delta electricity

Reserve Services in the NEM Directions Paper – current arrangements are not sufficient to provide in-market reserves

Current market arrangements are not adequate

AEMC limiting review to market uncertainty

- The analysis and basis for identifying the options appears superficial:
  - the AEMC makes the erroneous statement that *"Current arrangements are likely to provide sufficient in-market reserves to address expected events…"*. The reality is persistent, increasing and unprecedented AEMO and State Government market interventions.
  - the AEMC limits the consideration of reserve service to address AEMO market interventions arising from "…increasing variability and uncertainty…", whilst in SA the primary reason for intervention is a lack of essential system service resulting from synchronous thermal plant not running due to low spot prices[1].
  - the work of AEMO on the need for unit commitment for security and ahead decision making is ignored; and
  - an operating reserve option for ramping is proposed only for unexpected circumstances, yet AEMO in its Renewable Integration Study (RIS) Appendix C *"By 2025, VRE ramps are projected to have grown to the point where they are larger than underlying demand ramps 83% of the time."*

Only real time options presented

- An efficient operating reserve service mechanism should not exclude any technology, but should incentivise operational decisions, investment, innovation, and deliver net cost benefits.

A real time market limits available resource

- As identified by AEMO, reserve services are provided by technologies with delivery lead times of milliseconds to more than a day. The AEMC's proposed approach focused on only the fast response end of this spectrum – *"The set of resources available to respond to unexpected changes in RT [real time] conditions is more limited and is more likely to result in reserve shortages of periods of time in RT operations"* (s6.81 in FTI Report 'Essential System Services In The National Electricity Market' a report for the Energy Security Board (ESB) 14 August).

A real time operating reserve market will not work if the primary providers are not committed

- The ESB and AEMO have identified the benefits of unit commitment for security with decisions and an ahead decision process maximises the provision of economic reserve services. The timeframes for service provision are as relevant to reserves services and ramping, as it is for other essential system services.
- Operating reserve of conventional thermal plant simply may not be committed to meet the maximum NET demand.

VRE – non-synchronous variable renewable energy, both large and small scale.

1. AEMO Quarterly Energy Dynamics report Q3 2020

Executive Summary II

Reserve Services in the NEM Directions Paper – the review of operating reserves must include ahead unit commitment

Ramping service requirements grossly under-estimated

By 2025 the entire NEM is likely to be dysfunctional unless effective system service arrangements are implemented

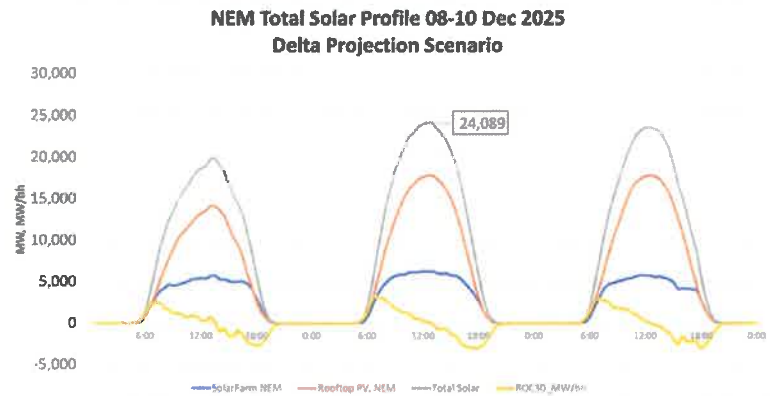
Primary objective should be the efficient elimination of directions and interventions

A holistic approach is needed given the overlap of ESS, ramping and reserve services

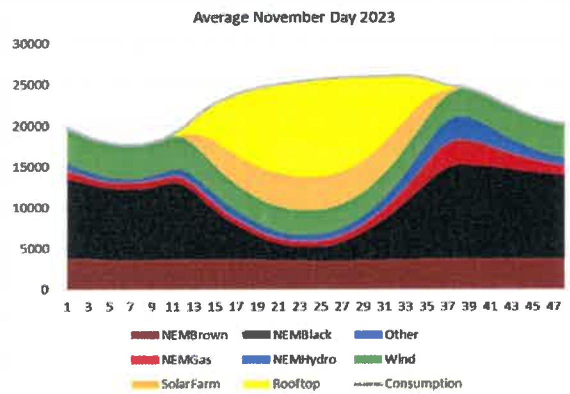
Create a market for these services and let the market invest and innovate

- The Directions Paper has not acknowledged the NSW Electricity Infrastructure Roadmap. When combined with other State based VRE underwriting schemes **AEMO's step change scenario** should now be the **central case**.

Extrapolation of current solar profile to 2025 under Delta Projection scenario shows +4,000/-3600MW/30min output change which will be on top of wind and underlying demand variability. Whether or not this is operationally feasible, it highlights the size of issue confronting the NEM in less than 5 years



Conventional thermal plant likely to be significantly displaced during solar hours and AEMO will be directing the market on a daily basis by as early as 2023 under a Delta Projection scenario in the absence of new market arrangements



- Delta's two rule changes (unit commitment for system security and reliability services and introduction of ramping services) address the projected market needs for reserves, ramping and essential system services on a technology neutral basis.

It is recommended the AEMC:

1. **broaden its consideration of reserve services and ramping to take account of the impact on market dynamics of State based renewable and storage support initiatives, specifically net demand trends and displacement of large thermal synchronous plant ; and**
2. **included Delta's unit commitment for operating reserves into its considerations.**

2. Operating the NEM – existing and evolving problems

I. Overview

The NEM is witnessing the start of a 'step change' in VRE and will need the bulk of existing large synchronous plant to remain viable in order to supply the essential operating reserves and ramping capability until new technologies can do so economically

- NSW, QLD and VIC all have programs to increase renewable energy generation, including designation of Renewable Energy Zones, targets and allocated funding. *"the NSW Roadmap includes a legislated amount of 12GW entering the system before 2030.This will put NSW on a transition pathway that is at least as fast as the Integrated System Plan (ISP) step change scenario"* *(ESB Directions Paper, Jan 2021 p22)*

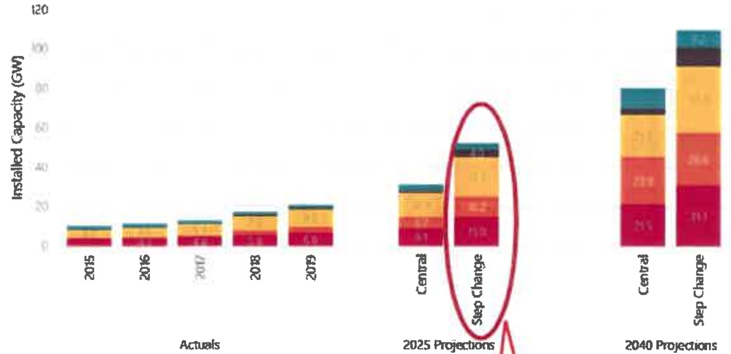
- The CER's studies estimate small scale solar installed capacity will increase by an additional **3,200MW per annum** for the next four years (CER's Quarterly Carbon Market Report – September Quarter 2020) on top of 3,000MW in 2020.

- The charts show projected VRE capacity will be multiples of average demand and with no deep storage. Big batteries, will only assist on the margin. The outlook for large thermal plant is early closure but what replacement technology can be rolled out in 4 years to keep the power system reliable and secure? The answer is none – the services of ALL synchronous plant must be valued in order for the NEM to operate efficiently and without intervention.

- The AEMC has not considered just how the market will work or how conventional thermal plant will respond. The operating reserve of large thermal plant simply may not be committed to meet the maximum NET demand.

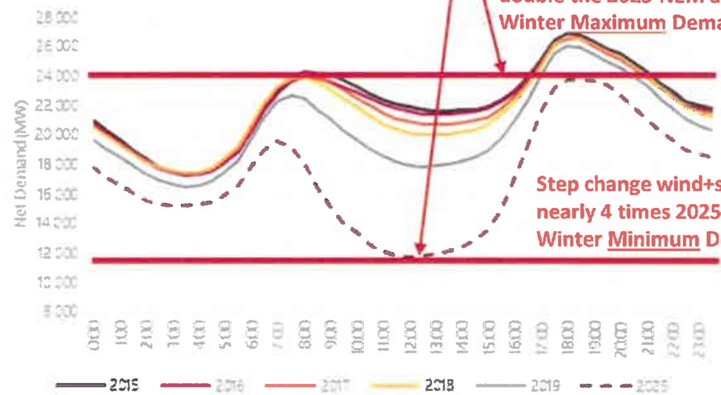
By 2025 the decommitment of thermal units as seen in SA due to high VRE generation will leave AEMO with a chronic and critical shortage of operating reserve, ramping and other ESS. In Delta's view this will already be emerging as a problem as early as 2022.

Installed wind and solar capacity in the NEM for 2019, with 2025 and 2040 forecasts from the Draft 2020 ISP Central and Step Change generation builds



Step change wind+solar capacity double the 2025 NEM average Winter Maximum Demand!

Figure 15 NEM average winter net demand curves



Step change wind+solar capacity nearly 4 times 2025 NEM average Winter Minimum Demand!

2. Operating the NEM – existing and evolving problems

II. Key facts

Consideration of operating reserves and ramping services should acknowledge that the power system will continue to rely on the essential system services provided by large synchronous generators, but these generators will not be operating without the right incentives.

- Historically, an abundance of inertia, system strength, voltage control, ramping has been provided by the thermal synchronous generators to maintain high levels of power system reliability and security – it was how the power system was designed.
- A broad market-based procurement mechanism for system services was not needed in the past and would not have delivered any meaningful price signal in any case. Only basic FCAS, network control and restart services were established.
- New interconnections, batteries, pumped hydro storage and synchronous condensers are assumed to replace the system services (including operating reserve and ramping) provided by existing large synchronous generators, but there is no clear picture as to how this can be done at the scale required, and in the time required, given the NEM outlook to 2025.
- The demand for operating reserve generating unit pre-commitment (e.g. day ahead) for the wide sustained swings in net demand (operational demand less VRE) over several hours and for sustained fast ramp capability are hugely understated in the Post-2025 Market Design Directions Paper:
  - the ESB Directions Paper projects that ramping requirements in the NEM could increase from 5,000MW over 4 to 5 hours in 2015 to around 12,000GW over 6 hours by 2025;
  - AEMO's RIS (app C page 34) – pre NSW Electricity Infrastructure Roadmap - projects the total ramp in Operational Demand for a 'representative' (ie not worst) Winter day in 2025 to be 15,954MW. Taking into account the higher rate of solar/wind build, Delta projects a worst case 2025 total solar ramp of up to 24GW; and
  - In NSW alone the daily ramp in Operational Demand is already large, up to 6,748MW recently (23/01/2020). This is significantly above the ESB's Directions Paper (page 26) assumed 5,000MW for the entire NEM.
- the thermal generators in NSW can deliver very high ramping (e.g. above 10MW/min) instantaneously from low loading levels but at a cost of increased wear and tear. Gas fired peakers out of service due to price, need 15 to 20 minutes before such services can be delivered. Hydro units can synchronise very quickly and provide high ramping but are energy constrained.
- **Establishing properly designed new markets will incentivise:**
  - **existing generators to be committed when required to provide operating reserve, ramping and other services; and**
  - **incentivise investment and innovation of new sources of essential system services in a timely and efficient manner.**

III. System security envelop and operational limits

The NEM is already operating at AEMO's limit. Action is urgently needed, and even interim measures should be on the table.

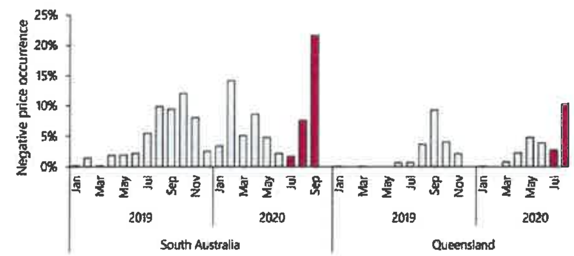
- As stated by AEMO[1] the NEM is currently limited to a maximum instantaneous penetration of wind and solar to between 50% and 60%. This could be increased to 75% with a range of measures. During Calendar 2020 the maximum instantaneous dispatch of wind and solar (incl rooftop) as a % of estimated consumption was 54%, i.e. already in the middle of AEMO's 'status quo' range.

- As State based VRE schemes continue to underwrite wind and solar, curtailment and dispatch uncertainty must increase:
  - new wind and solar projects will take increasing levels of curtailment into account in business cases, but Government support will override efficient investment and projects will be protected against falling prices;
  - during maximum solar periods generators will compete for dispatch, thermal units will initially reduce to minimum loads and VRE will bid below zero (e.g. $0/MWH SRMC less LGC price). Extended periods of very low prices (as is now being seen across the NEM) will incentivise conventional thermal units to decommit (e.g. Torrens Island in SA). A time will very soon be reached when thermal units will be removed from the market or periodically decommitted and consequently there can be no more reliance on this plant being on-line, available for essential system services, meeting evening peak demand or ramping services; and
  - until new technologies are developed and deployed over the long term, the NEM is limited in the amount of VRE it can securely dispatch.
- The Directions Paper has ignored these fundamental market dynamics and assumed, as all market design consultation papers blindly assume, that operating dispatchable thermal plant will continue to operate 24/7. Any consideration of operating reserves must acknowledge the changing market dynamics. The AEMC has failed to do so in its Directions Paper.

"If conventional units (typically coal) decommit for long durations, particularly during high periods of VRE penetration, the dispatchable flexibility from the fleet will be reduced .... To operate the system successfully, flexibility must be able to be scheduled in the right direction at the right time. Flexibility must be harnessed in all parts of the power system by enhancing traditional sources, as well as embracing emerging sources." (AEMO Renewable Integration Study Appendix C 5.2.5 p.59.)

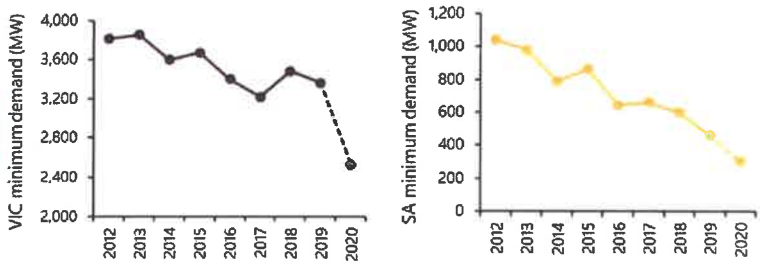
- In Q320, approximately 81% of direction costs were incurred in September, as record low South Australian spot prices during the **month meant GPG in the region frequently sought to de-commit from the market for economic reasons**. (AEMO NEM Quarterly Energy Dynamics Report Q3 2020).
- AEMO relies on directions to ensure sufficient convention thermal plant is committed. A market-based mechanism will reduce intervention costs and provide economically efficient reserve services – both MW and essential system services.
- all technologies should be incentivised to provide these services, and this means 'at the right time' as identified by AEMO.

Figure 9 Record negative price occurrences in South Australia and Queensland
Frequency of negative spot prices in South Australia and Queensland



Note 1: (Renewable Integration Study: Stage 1 report, April 2020, page 4)

Minimum Operation Demand (AEMO Q420 QED)



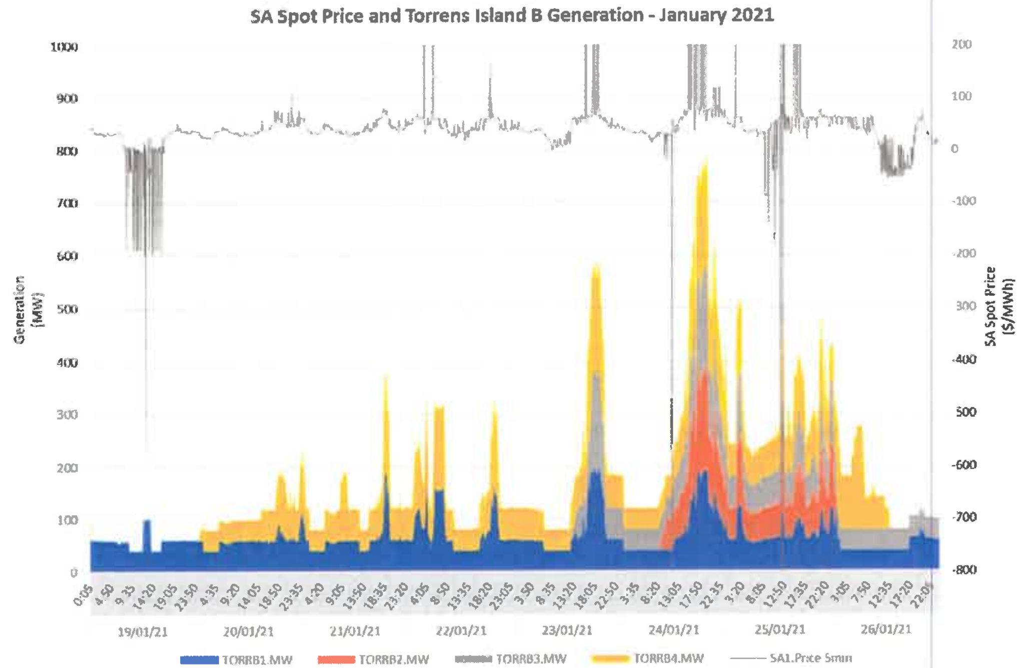
Falling minimum demand is only exacerbating the problems.

2. Operating the NEM – existing and evolving problems

IV. Current arrangements NOT likely to provide sufficient in-market reserves slide 1/4

The Directions Paper states that "Current arrangements are likely to provide sufficient in-market reserves to address expected events…". The evidence proves the exact opposite.

- AEMO's Quarterly Energy Dynamics reports demonstrate the growth of VRE continues to reduce the minimum regional levels of Operational Demand and reduces prices during the solar day:
  - *"New minimum operational demand records were set in South Australia (379 megawatts [MW]) and Victoria (3,073 MW)4, largely due to increased penetration of distributed photovoltaic (PV), with installations continuing at record levels"* – QED Q3 2020 p3; and
  - *"Negative wholesale electricity prices - During Q4 2020, negative and zero spot prices13 occurred in 7% of all trading intervals, surpassing the previous record set in Q3 2020 (4.6%), with calendar year 2020 averaging 4.4% compared to 1.7% in 2019. Negative spot prices were most prevalent in South Australia and Victoria, with both states reaching record quarterly levels. South Australia's spot prices were negative 17% of the time during Q4 2020, exceeding the previous quarterly of 10%, while Victoria reached a new record of 10%."* - QED Q4 2020 p12.
- Lower spot prices lead to thermal synchronous generators decommiting plant which impacts system security: *"The increased incidences of low system strength may be due to generally lower energy prices in South Australia, causing critical synchronous plant to be withdrawn for commercial reasons"* - AEMO 2019-20 NEM Summer Operations Review Report June 2020", page 56. These are the units most likely to be subject to market intervention by AEMO Directions.
- *"There were more directions in summer 2019-20 than in previous summers. In 2019-20, the majority of directions were issued to maintain system strength in South Australia."* AEMO 2019-20 NEM Summer Operations Review Report June 2020".



Torrens Island units have gas-fired boilers and exhibit similar characteristics to coal fired units. The chart above is a recent snapshot showing expected spot price responsive unit decommitment and dispatch. The issue is system services are required at all times and Torrens Island units are subject to direction like the gas turbine plant.

IV. Current arrangements NOT likely to provide sufficient in-market reserves slide 2/4

Market directions are largely limited to SA but this will change quickly as VRE growth in other regions continues. Properly designed new market mechanisms will replace inefficient directions with economic decisions by market participants.

- Market intervention by AEMO directions to generators has been growing, see Figure 27 from AEMO 2019-20 NEM Summer Operations Review Report June 2020",
- This trend has continued over the 2020 year, *"In 2020, total costs for directing South Australian generators for system strength was $49 million ($4.45/MWh), $23 million higher than 2019. During the quarter, AEMO continued to issue directions to GPGs in South Australia and initiated directing hydro generators in Tasmania to maintain system security.* "AEMO QED Q42020 p26.
- Victoria's flexible synchronous plant significantly supports SA's VRE across the interconnection. As VRE growth in VIC continues, that support will diminish. As evidenced by the period of SA separation, the number and total cost of SA directions can only grow, refer Fig 40 "AEMO QED Q42020 p26.
- Analysis of AEMO's Market Notices show that in Q4 2020 Directions to generators were issued on 33 days or an average of 2.5 days every week.
- This frequency continues with interventions on 8 days issued over the first 28 days in January 2021 – an average of 2 per week and also to 'maintain the power system in a secure state' in SA.

Figure 27 Number of summer directions issued in the NEM

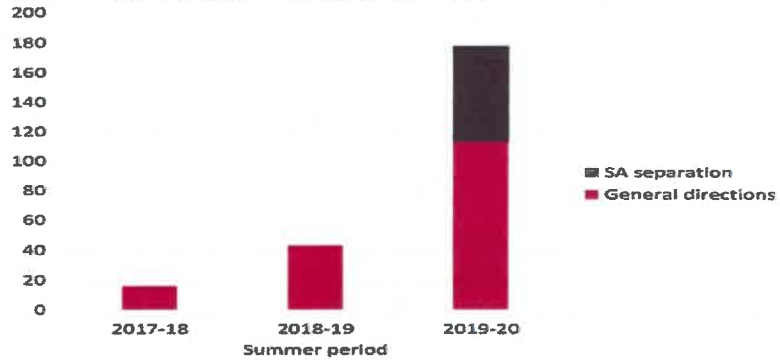
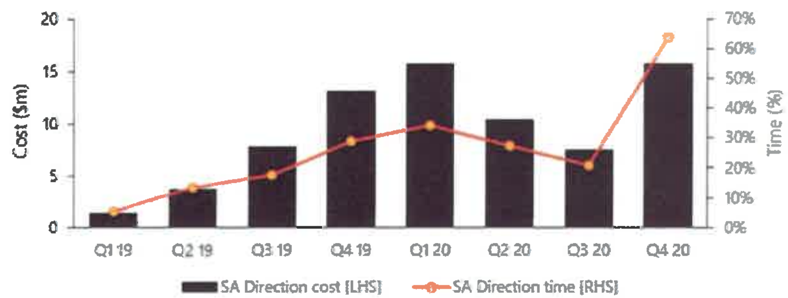


Figure 40 South Australian direction cost and time on directions increased significantly

Time and cost of system security directions (energy only) in South Australia



Note: direction costs reported are preliminary costs which are subject to revision

2. Operating the NEM – existing and evolving problems

IV. Current arrangements NOT likely to provide sufficient in-market reserves slide 3/4

Delta electricity

The RERT is the emergency backstop, and its summer activation suggests 'in market' arrangement are not working.

- NSW and VIC, regions normally considered 'rich' with synchronous generation capacity, are already showing occasional shortages in operating reserve (refer AEMO 2019-20 NEM Summer Operations Review Report June 2020).
    - All RERT activations during Summer 2019-20 were in NSW and VIC, regions normally considered 'rich' with synchronous generation capacity – see table1 from p6
    - "During the summer period from 1 November 2019 to 23 March 2020, AEMO declared a total of 28 LOR conditions (either forecast or actual). Of the 28 LOR conditions, the majority occurred in New South Wales, followed by Victoria." – see s4.3
- This trend will be exacerbated once thermal generators have to consider decommiting for commercial reasons due to reduced spot prices during the solar day.

Table 1 RERT activations over summer 2019-20

Activation date	NEM region	Maximum capacity of RERT activated (MW)	Volume of RERT activated (MWh)	Total RERT cost ($ million)[A]	Estimated avoided cost of load shedding based on VCR ($ million)[B]
30 December 2019	Victoria	92	283	$3.72	$11.66
4 January 2020	New South Wales	68	232	$8.36	$9.77
23 January 2020	New South Wales	152	456	$7.54	$19.21
31 January 2020	Victoria	185	697	$7.54	$28.72
31 January 2020	New South Wales	134	418.5	$10.93	$17.63
Total	-	-	2,086.5	$38.09	$86.99

A. Total RERT cost refers to pre-activation, activation and intervention costs (the compensation paid to Market Participants due to the intervention event (for example, to compensate for energy generation which is displaced by RERT capacity), and to Eligible Persons (SRA holders) due to changes in interconnector flows, and therefore changes in the value of Settlement Residues). It does not include availability costs.
B. The avoided cost of load shedding was estimated as the RERT activation volumes multiplied by the relevant VCR. VCR is the value of customer reliability, for further details, see https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/value-of-customer-reliability.

IV. Current arrangements NOT likely to provide sufficient in-market reserves slide 4/4

Delta electricity

A unit commitment mechanism is NOT an ahead market in the traditional sense. It takes account of the range of unit commitment advance notice requirements.

Current Arrangements Conclusions:

- The current market arrangements are already failing to yield sufficient in-market reserves and rely on increasing levels of direction and intervention by the AEMO.

- With the current arrangements NOT providing sufficient in-market reserves to address expected events the regulatory response must be to consider market mechanisms that will attract adequate reserves and ramping back into the market.

- Any market mechanism that fails to access the resources of the fleet of slow-start thermal generators risks not being able to provide the reserves required: "*The same demand curves are used to price reserve shortages in the day-ahead and RT markets, but most ORDCs rarely bind in the day-ahead market because the commitments needed to meet the reserve requirements can be made within the timeframe of the day-ahead market. The set of resources available to respond to unexpected changes in RT conditions is more limited and is more likely to result in reserve shortages of periods of time in RT operations*". Refer s6.81 of FTI Report 'Essential System Services In The National Electricity Market' a report for the Energy Security Board (ESB) 14 August 2020

- A day ahead market for reserve addresses the accessibility issue for legacy thermal plant. AEMO has proposed a Unit Commitment for Security mechanism with ahead decision making. "*We consider that there is potential for introducing ahead markets for the majority of ESS, including reserves, frequency response, as well as inertia and system strength* - The National Electricity Market' a report for the Energy Security Board (ESB) 14 August 2020.

V. Increased variability and uncertainty of supply and demand

Net demand projections for 2025 highlight need for both ramping capability (i.e. 1 hour) and operating reserve for ramping (i.e. 4 hours)

Take-outs from AEMO's Renewable Integration Study(RIS) 2020 Appendix C (study is pre-NSW Energy Infrastructure Roadmap) – likely ramping deficits by 2025:

- Net demand represents the underlying demand portion that AEMO must meet with the scheduled generation sources only, and not by wind or solar.
- "Historically, both demand and supply were relatively predictable. Today, as more VRE (such as wind and solar generation) is integrated into the grid, both supply and demand are more variable and harder to predict"
  - RIS Table 7:
    - indicates ramp rate capability need. 6147MW/hr up = ~100MW/min.
    - when prices are low, then no gas plant and only minimal hydro:
      - conventional thermal plant at 3MW/min (minimum mandated) = 33 units committed; and
      - conventional thermal plant at 5MW/min (normal) = 20 units committed.
    - batteries will contribute but only with price arbitrage (unless market for services established). Hydro is energy limited and will dispatch to maximise revenue over a longer time period. Hydro may not provide ramping unless energy prices are adequate.
  - RIS Table 8:
    - the longer time period indicates operating reserve for ramping.
    - when prices are low and gas plant is not committed:
      - 12992MW up must be supplied by hydro and from conventional thermal plant
      - assuming 2000MW hydro, QLD/NSW coal-fired units down 50% (~7000MW ramping with most units already committed) and VIC coal-fired turned down by 30% (1500MW), there is insufficient ramping capability and decommitted plant will be directed.

Table 7 NEM statistics of 1-hour underlying demand

	Maximum upward ramp (MW)				
	Underlying demand	Wind	Utility solar	DPV	Net demand
2015	2,871	843	94	710	4,189
2016	2,998	634	111	825	4,062
2017	3,209	873	145	977	4,043
2018	3,661	911	635	1,238	4,240
2025	3,292	2,313	3,014	2,214	6,147

Table 8 NEM 4-hour net demand ramp statistics

	Average	Maximum	
	MW	Upward (MW)	Downward (MW)
2015	2,627	9,934	-6,449
2016	2,619	10,163	-6,701
2017	2,718	9,062	-8,600
2018	2,772	9,758	-7,415
2025	3,521	12,992	-11,517

VI. Instances of market failure are increasing

Source: Charts extracted from AEMO Quarterly Energy Dynamics report Q420

Increasing cost of directions, VRE curtailment and negative prices are all examples of market failure

- SA is only achieving high levels of VRE due to interconnection to VIC which has conventional fully dispatchable synchronous plant providing operating reserves and other essential system services.
- The summer 2019/20 SA separation highlighted the operational issues and costs of operating a stand-alone power system with high levels of non-synchronous plant.
- As VIC, NSW and QLD VRE trends towards SA levels, the NEM will experience the same issues as a separated SA region.
- To avoid increasing instances of market failure, operating reserve, ramping and essential system service markets are urgently needed.
- These new markets must capture the services of large synchronous plant and, as such, must allow at least day ahead decisions to capture commitment timeframes.

Figure 39 VRE curtailment returns to near record levels
Average NEM VRE curtailed by curtailment type

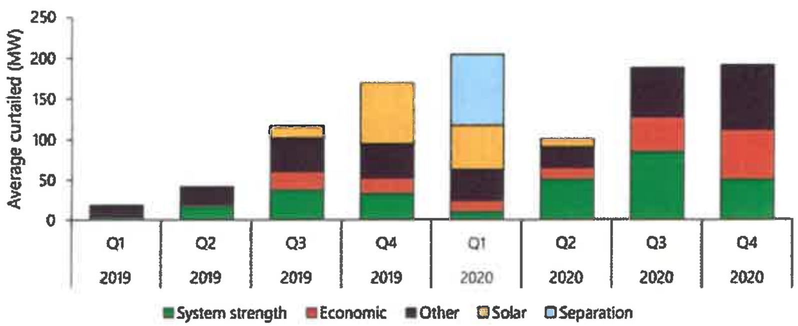


Figure 14 Negative spot prices hit record levels in South Australia and Victoria
Quarterly negative price percentage occurrence

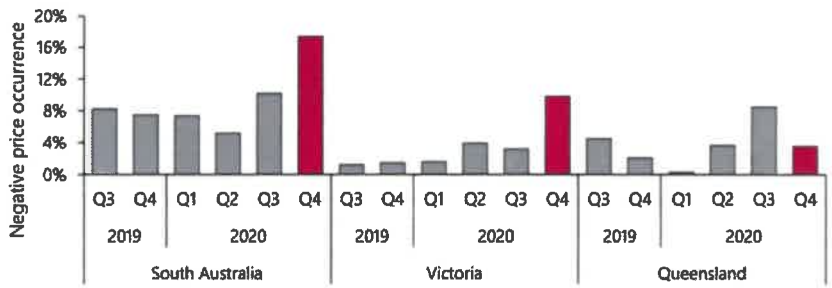
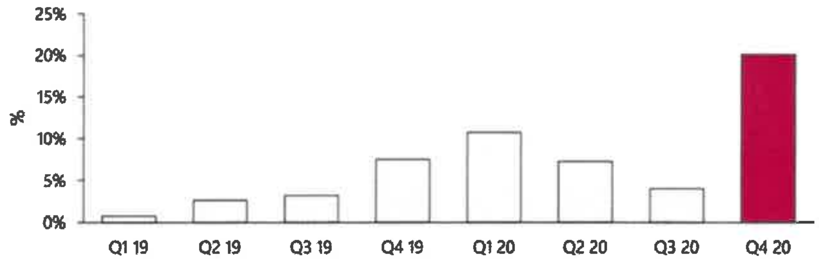


Figure 41 Average SA GPG directed reached record highs, accounting for 20% of total average output
% of South Australian GPG directed – Q1 2019 to Q4 2020



"...approximately 81% of direction costs were incurred in September, as record low South Australian spot prices during the month (Section 1.3) meant GPG in the region frequently sought to de-commit from the market for economic reasons." AEMO Quarterly Energy Dynamics Report Q3 2020

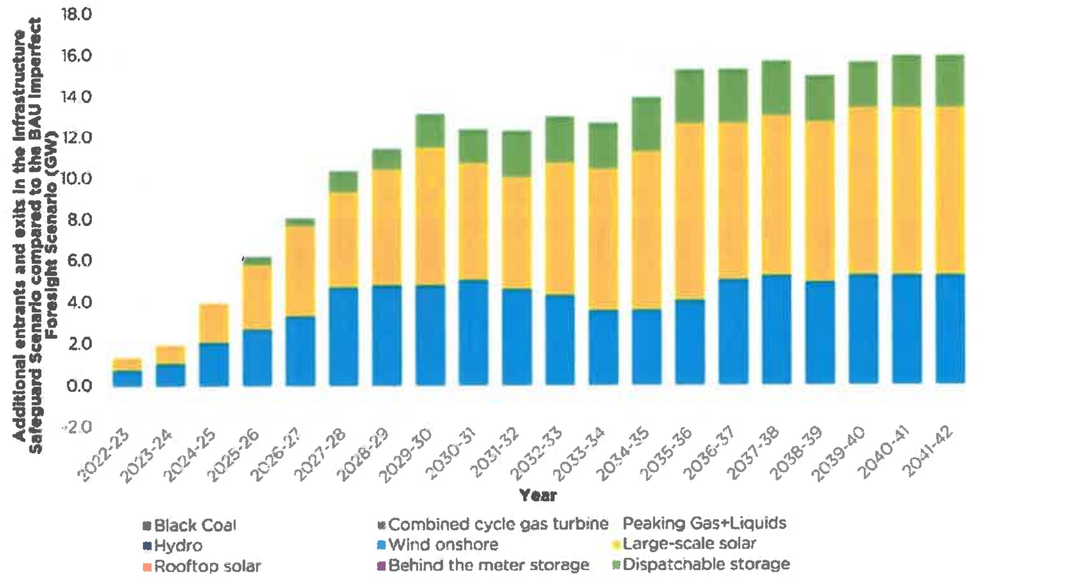
VII. Ramifications of State based electricity infrastructure support schemes on the NEM

NSW Electricity Infrastructure Roadmap –12GW of VRE and 3GW of deep storage – is a game changer and removes any doubt about the need for market reform

- Legislation has passed through the NSW Parliament (assented on Thu 3 Dec 2020).
- In 2020 NSW has around 4000MW of grid-scale wind and solar.
- By FY25 the Roadmap will deliver an additional 4000MW of wind/solar (no storage), and a further 2000MW by FY26 (note these are additional to business-as-usual outcomes).
- The Roadmap's consequences by 2025:
    - maximum wind/solar max generation = ~10,600MW, well beyond the current 60% limit as advised by AEMO on average NSW operational demand (~7,700MW);
    - over 1,040MW/hr additional ramping just from Roadmap grid-scale solar alone;
    - **VRE + minimum thermal generation > average demand**;
    - underwritten VRE will be indifferent to market prices; and
    - significant further pressure on daytime prices.
- Large NSW thermal generators will be displaced but will still be needed for MW reserve at evening peak demand and system security.
- Based on SA experience, AEMO will effectively be directing market interventions in NSW.
- Consideration of operating reserve options must take full account of the implications from the Roadmap on NEM operations, otherwise solutions will not be 'fit-for-purpose'.
- **It is imperative the AEMC rethink operating reserve as all technologies will be needed to deliver system reliability and security in the near future.**

NSW Generation Capacity Mix

The modelling assumes that the Infrastructure Safeguard will deliver approximately 12 GW of additional generation capacity by 2030 in NSW compared to the BAU Imperfect Foresight Scenario.



NSW Electricity Infrastructure Roadmap report - November 2020

VIII. Summary

Delta electricity

Energy only market price incentives alone cannot ensure all operating reserve resources will be committed when required.

↓

The projections for operating reserve and ramping are underestimated

↓

AEMO cannot rely on frequent market directions across the entire NEM – impractical, costly, inefficient.

↓

A range of commitment decision timeframes needed to ensure efficient use of resources for operating reserve.

↓

The NEM needs to be enhanced to incentivise the commitment of slow start synchronous units where economically efficient to ensure adequate supply of operating reserves and ramping.

↓

AEMC must expand its consideration of operating reserve/ramping to:

1. **include the implications of the NSW Roadmap; and**
2. **take account of the range of operating reserve trigger timeframes**

"…the NEM was not designed for managing minimum conditions (particularly managing the commitment of synchronous units, to maintain minimum levels of inertia and system strength)."

AEMO Renewable Integration Study April 2020

"The market will become increasingly difficult to operate without centrally procured operating reserve."

AEMO Submission to the AEMC's Consultation Paper – System Services Rule Changes August 2020

"Most electricity markets around the world mobilise operating reserves in a range of different timeframes, to ensure the most efficient combination of resources is able to be dispatched when needed. For instance, **operating reserves could be triggered on a day-ahead**, hour-ahead, or 15-minutes ahead basis."

AEMO Power System Requirements Report July 2020

I. Adequacy of analysis

Delta electricity

The Directions Paper has not explained how the range of options were determined or detailed the criteria against how each option should be re-assessed.

- The assessment of reserve services by the AEMC is highly problematic:
  - no appreciation of the massive impact on the future dynamic of NEM operations arising from State based renewable energy support schemes (ie. frequent pressure to decommit due to low/negative prices during high VRE output);
  - no substantiation of statement that current arrangements are likely to provide sufficient in-market reserves to address expected events;
  - fails to deal with the linked major and growing problem of market interventions by AEMO; and
  - no account of the timeframes for the delivery of reserve service and thereby is not technology neutral.

- Delta believes that paragraph 14 of the Executive Summary

  "The current real-time energy market framework with the existing structure of market settings (i.e. market floor price, market price cap, cumulative price threshold and administrative price cap) has effectively achieved this to date. It is designed to incentivise the entry and exit of equipment necessary to meet this need for each dispatch interval, to the level consumers value."

  does not comport well with actual experience, especially in South Australia, recognised in paragraph 15 "The specific problem this gives rise to, and which we consider needs to be addressed, is the inefficiency of interventions in the market to ensure there are sufficient reserves…"

II. Reserve service options

Without a day-ahead commitment mechanism it is hard to see how available resources will optimally utilised. The real time mechanisms will incentivise the provision of some reserves but based on projections AEMO will still be intervening in the market..

AEMC Options	Pros	Cons	
Co-optimised operating reserve market	Real time scarcity pricing should ensure least cost supply of readily available resources Co-optimised will avoid consumers paying for services not required Will incentivise new very fast response technology Will incentivise fast start resources to be available Will only incentivise slow start resources on the margin	Targets reserves that can be provided instantaneously. Does not account for the workings of NEM with high levels of underwritten and subsidised zero SRMC generation. Real time price signals are highly uncertain. The commitment of a large slow start unit will invariably have a material impact on the real time price. These dynamics mean a highly costly slow start commitment decision will only occur when there is significant reserve/ramping scarcity. Co-optimisation may be complicated to implement effectively given the real time nature of the proposal. <u>Will not deal with AEMO directions and therefore unlikely to deliver net market benefits.</u>	As proposed by AEMC, these three options have no provision to accommodate a range of commitment timeframes, these options are therefore not technology neutral because they exclude slow-start generation and risk shortfalls against ESS criteria because they don't make use of all available resources. Any new mechanism must significantly reduce AEMO directions as this where a great deal of the benefits will arise. The AEMC options only partially solve this issue.
Co-optimised availability market	'as above' 30 minutes brings in additional resources Provides greater assurance of supplies over option 1.	'as above', plus some concern over the potential conflict of the current NEM Rules obligation to truthfully advise AEMO of plant physical availability versus "offering availability". Re-badging in-market capacity does not add additional reserve MW.	
Callable operating reserve market	Goes some way to encompassing range of resources – fast start gas turbines only. Gives AEMO more time to respond to changing conditions.	'as above' Still limited to 30-min commitment timeframe.	
Ramping commitment market	Consistent with existing ancillary service arrangements making implementation easier. Will incentivise the provision of capability, investment and innovation.	Operating reserve and ramping capability are connected and the primary providers of ramping over the medium term need price signals to committed during periods of very low prices.	

III. Reserve service options Summary

In summary:

- The operating reserve market options in the AEMC's Directions Paper fails to consider the decision timeframe for some technologies.
- Delta considers the exclusion of ahead solutions (such as Delta's Capacity Commitment Mechanism) in the Directions Paper to be unfortunate, contrary to AEMO's own conclusion[1] and therefore carries the risk of suboptimal recommendations on operating reserve arrangements considered in isolation.
- The ramping commitment option, as proposed by Delta, is linked to Delta's unit commitment for operating reserve proposal which is not explored in the Directions Paper. The combination of Delta's proposals would:
  - address the decision timeframe deficiency of the AEMC options;
  - address the pressing need to significantly reduce AEMO directions;
  - deliver a technology neutral market-based mechanism that incentives economic provision of operating reserves for reliability and security and ramping;
  - incentivise investment in new technologies; and
  - will REDUCE costs to consumers as the inefficiencies of directions will be replaced with the competitive provision of requires essential services.

Note 1: AEMO Submission to AEMC ref ERC0290 dated 13 August 2020 – refer Conclusions, p21

4. Proposed solutions

I. Delta Electricity Proposals

Delta has proposed two system services rule changes to the AEMC that, while separate and individually meritorious, Delta considers would operate in a complementary manner:

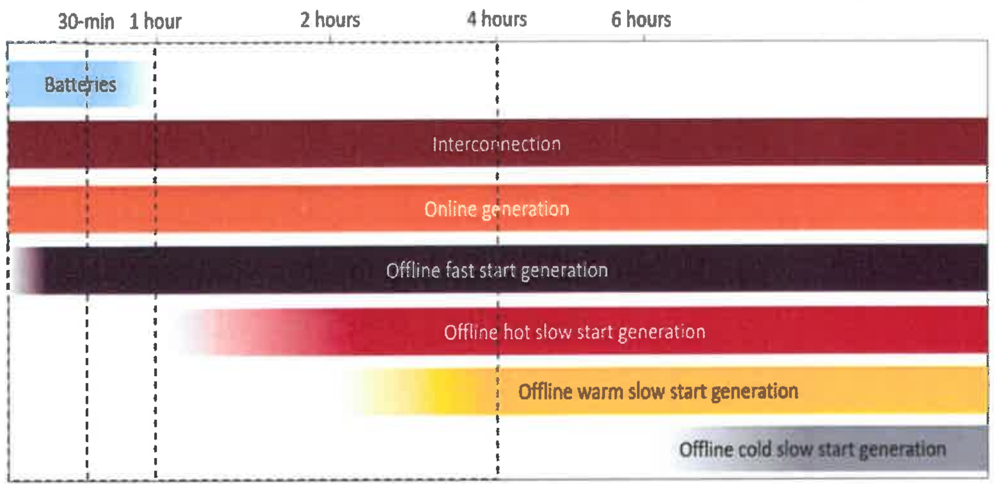
- a day-ahead Capacity Commitment Mechanism: 'NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services'[1]; and
- new 30-minute Ramping Services: 'NEM Rule Change Request - New 30-minute FCAS Raise and Lower Services'[2], intended to be co-optimised with energy and other FCAS services as existing FAS services are.

Note 1: AEMC reference ERC0306, Capacity commitment mechanism for system security and reliability services | AEMC
Note 2: AEMC reference ERC0307, Introduction of ramping services | AEMC

The decision timeframes for slow start plant to return to service can require day-ahead commitment.

- As identified by AEMO, reserve services are provided by technologies with delivery lead times of milliseconds to a day. "The set of resources available to respond to unexpected changes in RT [real time] conditions is more limited and is more likely to result in reserve shortages of periods of time in RT operations" [1].
- The ESB and AEMO has identified the benefits of unit commitment for security with decisions and an ahead decision process maximises the provision of economic reserve services, including some Demand Side Response resources. The timeframes for service provision are as relevant to reserves services and ramping, as it is for other essential system services.
- Conventional thermal plant has commitment lead times of around:
  - 2 to 4 hours if only just taken out of service (hot start);
  - 10 to 24 hours if the unit has been out of service for a number of hours (warm start); and
  - Around 24 hours if the unit has been out of service for a day or more (cold start)
- Even with a hot start, conventional thermal units do not have the same return to service reliability as gas plant.
- Restarting a conventional thermal unit requires significant amount of liquid fuel (e.g. diesel) to start. Cost can be $200k for a cold start.
- A conventional thermal unit will only be brought back into service if market returns will cover the start cost and the uncertainty of the synchronisation time.
- As noted by AEMO[2] the market is under pricing and undervaluing reserves and without a guarantee of a price outcome, slow start plant needed for reserves, ramping or other essential system services will not commit.
- Without day ahead decision making, the SA experience with AEMO directions will simply be replicated across the NEM but also include directions on conventional thermal plant.

Chart 1 - Ramping resource start up times



AEMO, Renewable integration Study stage 1 appendix C, April 2020

Note 1: s6.81 in FTI Report 'Essential System Services In The National Electricity Market' a report for the Energy Security Board (ESB) 14 August.

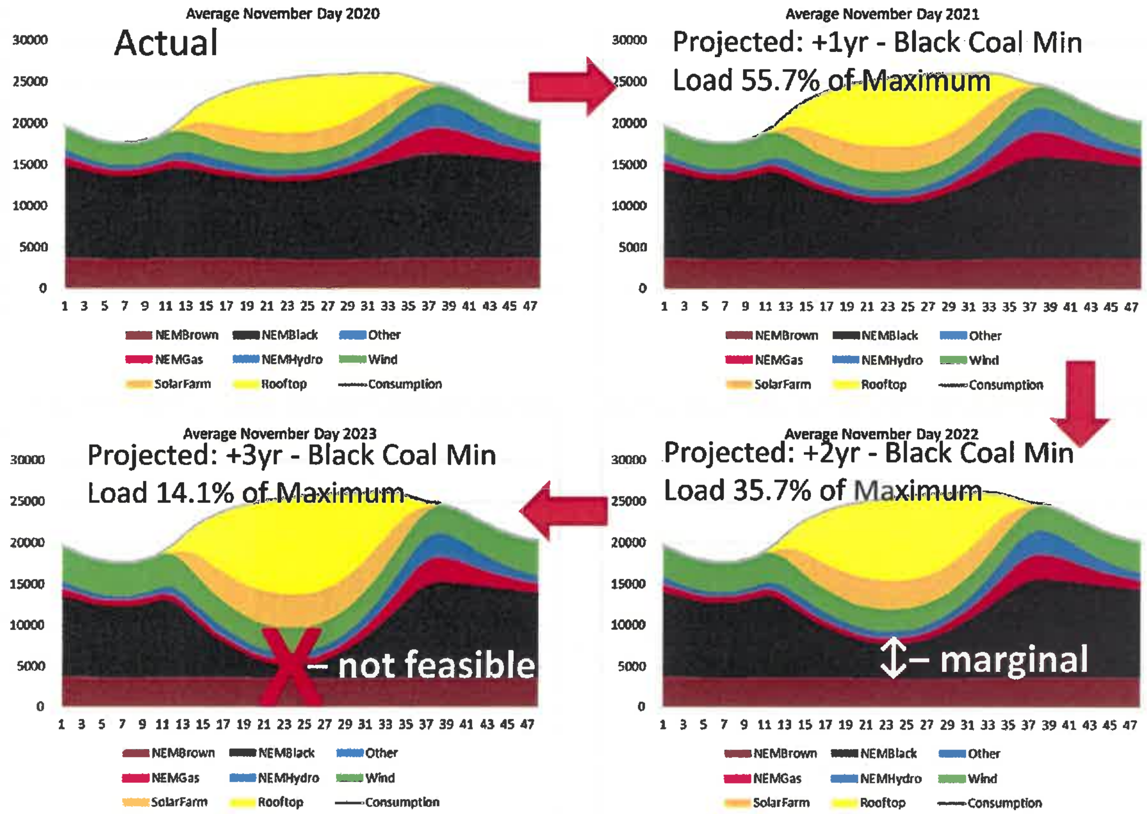
Note 2: AEMO Submission to the AEMC's Consultation Paper – System Services Rule Changes August 2020

4. Proposed solutions

III. Unit commitment mechanism for operating reserve and essential system services slide 1/3

Slow-start thermal generators on standby are unavailable to meet the evening peak or provide any system services

- The issue of large synchronous generators decommiting due to the pace of new VRE build is urgent.
- VRE is displacing predominately conventional thermal (primarily black coal) generation.
- Conventional thermal generators can 'turndown' to a minimum stable operating load (MSOL) of ~30-50% of capacity (brown coal generators can turn down to ~60-80% of capacity)
- Turndown to 35.7% capacity is marginal for many units* and to 14.1% is not feasible. Large synchronous generators will be forced to decommit on occasions in 2022 and frequently in 2023.
- Decommitted slow-start generators are unavailable to meet the evening peak, sudden changes in VRE or provide any ESS.



Note* projected instantaneous VRE penetration in 2022 would exceed 50% on 333 days and 60% on 275 days, well in excess of AEMO's RIS thresholds

4. Proposed solutions

III. Unit commitment mechanism for operating reserve and essential system services slide 2/3

Standby thermal units to decommit impacts system security and reliability

- Slow-start thermal gens on standby are unavailable to meet the evening peak or provide any ESS such as inertia.
- AEMO's 2020 ISP already shows that for the 'Step Change Scenario the NEM 'Inertia Initial Safety Net' is in shortfall 20% of the time by 2024-25; and the NEM Minimum Inertia is in shortfall approximately 10% of the time by 2029-30.
- AEMO's assessment of available inertia is unlikely to have taken account of slow-start unit decommitment for commercial reasons.
- Large synchronous generators being forced to decommit on occasions in 2022 and frequently in 2023 means that those occasions are likely to also involve shortfalls inertia.
- In the absence of a **day-ahead commitment mechanism** AEMO will be forced to use market intervention to direct generators to commit, as it has in South Australia.

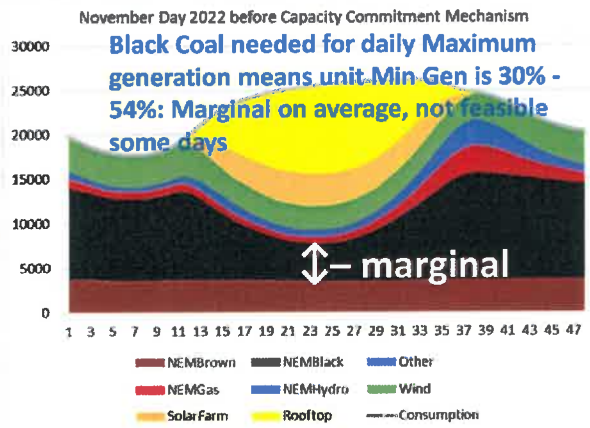
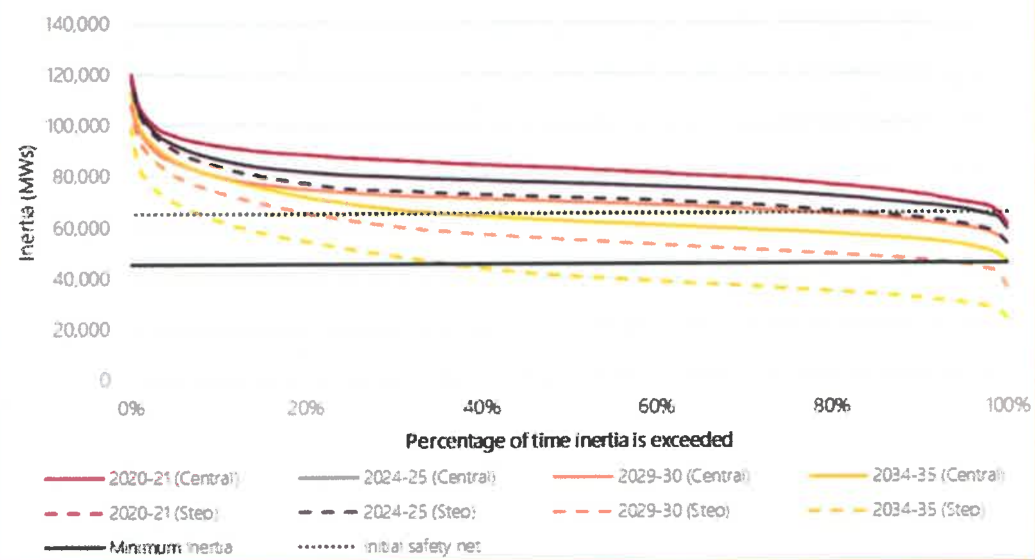


Figure 28 NEM mainland inertia outlook (Tasmania excluded), Central and Step Change scenarios

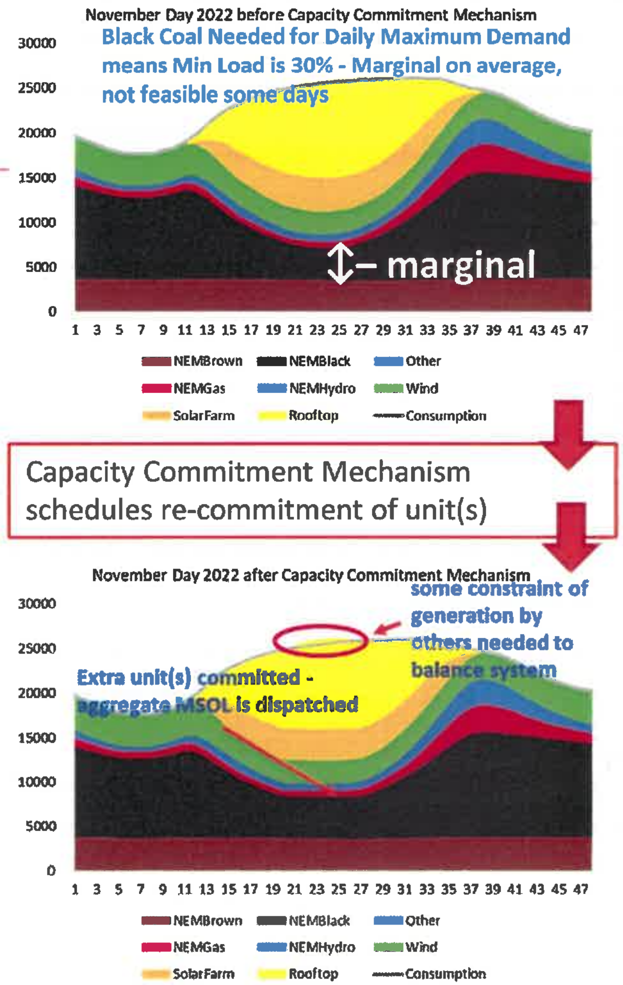


4. Proposed solutions

III. Unit commitment mechanism for operating reserve and essential system services slide 3/3

The unit commitment mechanism will deliver a similar commitment outcome to directions, but more efficiently and at less cost.

1. Participant registration: includes capability for all ESS: e.g.voltage and frequency control, inertia and ramp rates, Minimum stable operating levels.
2. Participants make daily offers to AEMO
3. AEMO forecasts day-ahead requirements for dispatchable synchronous capacity, Operational Reserve and ESS and compares with its established standards for system security and reliability.
   i. If there is no shortfall in Operational Reserve or other ESS then the day-ahead commitment market clears at zero.
   ii. If there is a shortfall in Operational Reserve or other ESS then AEMO clears bids in the day-ahead commitment market to remedy the shortfall(s) then runs predispatch achieving optimal system costs.
4. The day-ahead commitment market is cleared with sufficient time for large thermal units to re-commit and meet their obligations under the Mechanism.



4. Proposed solutions

V. Need for a ramping service

Delta proposed a new 30-minute Ramping FCAS product because by 2025 fully dispatchable units must ramp down up as much as 24,000MW in the morning and ramp up as much as 24,000MW in the evening to accommodate just the aggregate solar profile.

Scenario	Maximum ROC, MW/half-hour	Total Ramping, MW
2019/20 Actual	1,328	8,425
2024/25 – Delta extrapolation	3,995	24,089

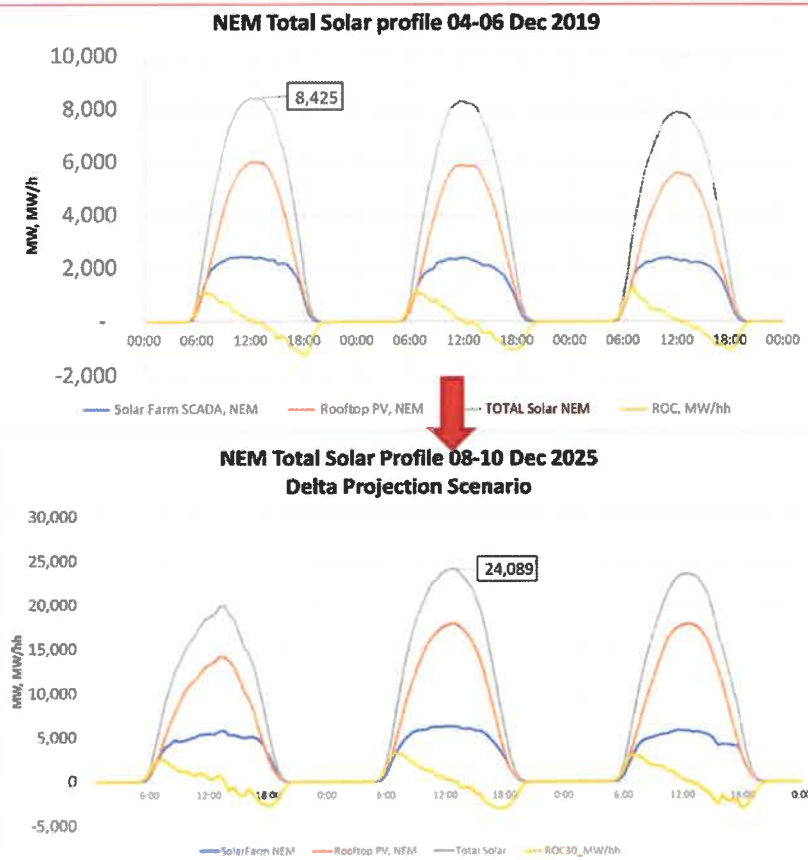
The near-tripling of the solar ramp between now and 2025 would be an 'expected event' but AEMO needs to manage not only the solar ramp but also the 'unexpected' events of various contingencies which will on occasion be coincident with the solar ramp. Delta's estimate of the Maximum ROC of the NEM Net Demand (Consumption less VRE, based on 2020 dispatch patterns) which can only be met by synchronous generators is +4,435/-3102 MW/half-hour.

By 2024/25 the 24,089MW Solar Ramp alone (ie. ignoring Wind or other coincident system events) exceeds existing peaking/fast start capacity which could be dedicated to managing the ramp:

- Gas:
    - total available capacity = 12,157MW* (Max 2020 co-incident NEM Gas generation = 8,212MW)
    - Start times around 15 minutes (longer for CCGT or Gas-fired boiler/stem turbine units)
    - SRMC above $70/MWh likely to be above market prices at the time solar is coming off
- Hydro: 7,982MW* (Max 2020 co-incident NEM Hydro generation = 6,009MW)
- conventional thermal: approx. 22,000MW

Source: AEMO Jan 2021 NEM Generation Information*

CONCLUSION: the NEM will continue to need ramping from slow-start units for many years as new solar VRE continues to add 3,000MW-4,000MW per annum to the Total Solar Ramp:



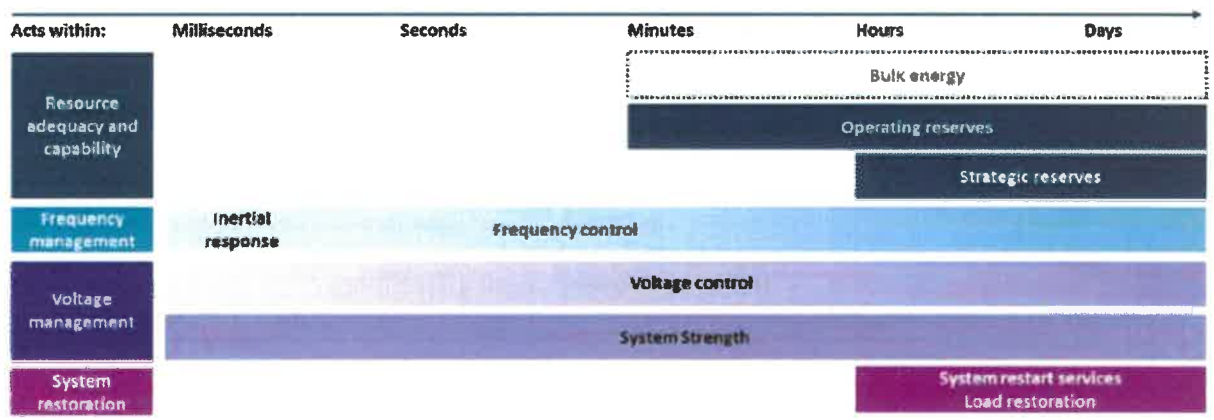
Delta electricity

THE BOTTOM LINE ....

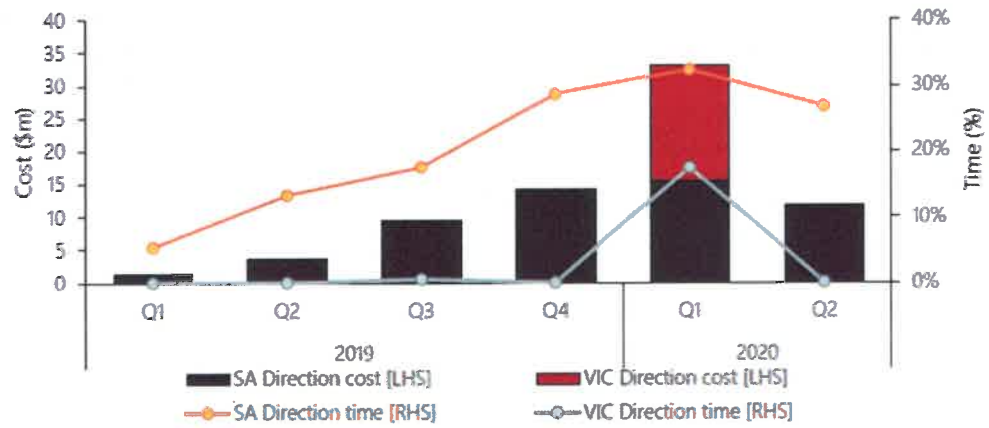
- The AEMC's Directions Paper is based on information that does not recognise the impact of high VRE on the commercial operations of slow-start thermal generators – in particular the decommitment of conventional thermal units to avoid the costs of remaining committed through low or negative price periods.
- As a result, the Directions Paper presents options that will not incentivise large thermal units to commit to operations during periods of scarce operating reserve, ESS and ramping capability (e.g. conventional thermal units may remain on standby).
- The Directions Paper options are not fit-for-purpose for the transitional years of the NEM and that, if adopted without a day-ahead commitment element, will lead to increasing market intervention by AEMO to bring back stand-by capability to the market.
- Delta commends to the AEMC its proposed 'Capacity Commitment Mechanism for System Security and Reliability Services' to provide a market-based solution for AEMO to bring back stand-by capability to the market.
- Delta's proposed 30-minute Ramping FCAS service is designed to meet a separate, distinct challenge in the market, a challenge which will grow to dominate the daily operations of a High-VRE NEM and this proposal should be considered in addition to whichever Operational Reserve solution is adopted.

<table>
<tr><th>AEMC Question</th><th>Delta Electricity Response</th></tr>
<tr><td>QUESTION 1: THE NEED TO ADDRESS VARIABILITY AND UNCERTAINTY
1. What are stakeholder views on the issues identified, in particular, on whether the primary issue is appropriately characterised as an increased risk of insufficient in-market reserves being available to meet net demand, due principally to forecast uncertainty and net demand variability as the penetration of VRE generation increases?</td><td>Delta is of the view that yes, the increased uncertainty and variability in operational demand, due to increasing penetration of VRE, does create additional risk of periods of insufficient reserves to meet net demand.

This characterisation of the primary issue is too narrowly defined and that insufficient reserves due to increasing penetration of VRE also causes additional risk of insufficient other Essential System Services (ESS) besides operational reserves such as inertia, frequency control, voltage support, and system strength (refer Figure 2-1 below, from page 19 FTI's report to the ESB 'Essential System Services In The National Electricity Market' dated 14 August 2020 and definitions in section 2):

Figure 2-1: Overview of current categories of ESS in the NEM


Source: FTI analysis based on AEMO, Power system requirements, March 2018 (link), page 9.</td></tr>
<tr><td></td><td>The high levels of market intervention prevalent in South Australia are indicative of the outcomes that will emerge in other Regions over time as VRE increases and legacy thermal plant is removed from service.</td></tr>
</table>

AEMC Question	Delta Electricity Response
	Delta strongly disagrees with the statement in the Directions Paper that "Current arrangements are likely to provide sufficient in-market reserves to address expected events" given the evidence to the contrary: the persistent interventions in South Australia are primarily directions issued by the Market Operator to out-of-service thermal plant (i.e. capacity that is not in-market), are by their nature a signal that the market design is deficient and is NOT yielding 'sufficient in-market reserves'. This reliance on market intervention should be replaced by market-based mechanisms that will provide a price signal for both the commitment of existing capacity and investment in new capacity. Delta supports the development of market-based solutions to the issues raised above.
2. What are stakeholder views on the materiality of these issues? For example, are the issues material enough to warrant the further development of a reserve service market?	The costs of Directions in South Australia over 2019-20 totalled approximately $49.7m, refer Figure 41 from AEMO's Q2 2020 Quarterly Energy Dynamics report: **Figure 41 South Australian directions cost remain comparatively high** Time and cost of system security directions (energy only) in South Australia and Victoria  Note: direction costs reported are preliminary estimates which are subject to revision. Amortised over the 2019-20 sum of operational demand of 11,168,612MWh this represents a regional cost of $4.45/MWh. The 2019-20 average SA spot price was $62.03/MWh, which means the Regional costs of direction represent an additional 7.1% on top of the Region's wholesale energy costs.

AEMC Question	Delta Electricity Response
	This is very material given the trends of increasing frequency of directions due to increasing penetration of VRE.
3. If not, what further information would be required relating to the nature of the issues facing the power system before progressing the development of a reserve service market?	As stated above, interventions in South Australia are primarily directions issued by the Market Operator to out-of-service thermal plant are by their nature a signal that the market design is deficient and is NOT yielding 'sufficient in-market reserves', contradicting the statement made in the Directions Paper that "Current arrangements are likely to provide sufficient in-market reserves to address expected events"[1]. In terms of timing, there is a clear and present need for developing market mechanisms to better manage shortfalls of reserve and/or other ESS, especially in South Australia. Delta agrees with the AEMC's statement in its 5 January Media Release that "Redesigning the energy market can't wait". The AEMC should also consider the merit of interim solutions which hold the promise of the early delivery of an outcome to address market needs while the design of a more perfect market solution continues: "Perfect is the enemy of good"[2]. Deployment of these market mechanisms NEM-wide will yield important early price signals to provide the market with the information it needs to take steps to address the supply of reserve and/or other ESS in other Regions before actual shortfalls become chronic.

[1] AEMC: 'Reserve Services in the National Electricity Market, Directions Paper', 5 January 2021, paragraph 15.
[2] Voltaire: 'Dictionnaire Philosophique' https://en.wikipedia.org/wiki/Dictionnaire_philosophique, 1770

AEMC Question	Delta Electricity Response
QUESTION 2: OPTIONS TO ADDRESS VARIABILITY AND UNCERTAINTY OF NET DEMAND 1. To what extent could any or all of the incremental improvements to current arrangements set out in section 6.1 address the issues sufficiently to negate the need to implement a new reserve service market? Are there any other incremental improvements that should be considered?	Incremental improvements will not address the fundamental issue of market dysfunction – AEMO directions, VRE curtailment and negative prices. The quantum of the effect of these incremental options and their realistic timetable for delivery does not mean that they can be considered as a substitute for decisive action to address a current need - "Redesigning the energy market can't wait"[3]. The implementation of an interim solution, as suggested in the answer to Question 2 part 3 below, could be considered as an incremental improvement on the basis that it does not preclude the subsequent development, deployment and operation in parallel of a fully integrated solution co-optimised in NEMDE. The interim solution could be retired when the 'ahead market' aspect that it provides ceases to be useful to operation of the NEM.
2. Which of the reserve service market options set out in section 6.2 is the most preferable to address the issues raised in Chapter 5, taking into account the way different technologies may operate under each option and the trade-offs between the options?	Operational Reserves The Directions Paper says "Out-of-market reserves are procured for specific purposes. For example, the Reliability and Emergency Reserve Trader (RERT) which is used as a last resort to meet demand."[4], it omits to mention that the largest out-of-market source of reserves are generators that are decommitted but available for re-start. This is the category of reserve capability that is subject of most SA market interventions and **this is the category that should be targeted in any new reserve services market.** Delta is not convinced of the worth of any mechanism that simply re-prices or re-categorises (e.g. energy ↔ reserve) current in-market capacity – the energy and FCAS markets can already do that. Under current market rules generators must truthfully declare to the Market Operator their generator's physical availability (MAXAVAIL – a figure that may be different to nameplate rating depending on any plant limitations at the time) so that the Market Operator has an accurate measure of total in-service capacity. The idea that participants may re-bid 'availability' to anything less than their physical maximum availability is disturbing as it implies the Market Operator's knowledge of total in-service capacity may be obscured by participant bidding behaviour.

[3] AEMC Media Release '"Redesigning the energy market can't wait" 5 January 2021.
[4] AEMC: 'Reserve Services in the National Electricity Market, Directions Paper', 5 January 2021, paragraph 10.

AEMC Question	Delta Electricity Response
	Delta considers the objective of a reserve mechanism should be to find sufficient out-of-market capacity, whether out-of-service generation or demand side resources similar to RERT that is prepared to re-commit and then be dispatched in accordance with its energy bids. The key issue is the commitment timeframe. Delta is opposed to limiting the commitment timeframe to suit a narrow range of technologies. A co-optimised operating reserve market is preferable providing it accommodates a full range of commitment timeframes and can be implemented cost effectively. The presentation of options in the Directions Paper has mischaracterised Delta's 'NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services' by not including it with the options presented in Section 6.2. – refer Delta's response to Question 2 Item 3 below. <u>Ramping Services</u> The inclusion of 'ramping services' is understandable and a reference to its 'NEM Rule Change Request - New 30-minute FCAS Raise and Lower Services' [5] also addresses aspects of the Operational Reserve problem. In a sense this is a positive by-product of a rule change Request that was proposed to specifically address a different problem: the sustained ramping obligations imposed on the balance-of-system by the aggregate solar generation profile and wind generation changes. To the extent that ramping services can deliver capacity to address Operational Reserve requirements, Delta supports that as a co-optimised component of the overall solution. Co-optimising services across the energy, FCAS and ESS services is an important principle in minimising costs and achieving the Delta considers that its ramping services proposal is misrepresented in the Directions Paper which states "This approach does not co-optimise the procurement of ramping capacity with the procurement of energy and FCAS"[6] which is not what Delta proposed. Delta's stated intention in the Rule Change request was that implementation as new FCAS

[5] AEMC reference ERC0307, Introduction of ramping services | AEMC
[6] AEMC 'Reserve Services in the National Electricity Market, Directions Paper', 5 January 2021, Section 6.2.4 page 47

AEMC Question	Delta Electricity Response
	services meant that it **would** be co-optimised with the energy and other FCAS markets: "As with FCAS services, a co-optimisation process would need to occur."[7]. Co-optimisation is facilitated by Delta's Rule Changes as a value for operating reserve and ramping allows numerical calculations of optimised total delivery of energy and essential system services.
3. Are there any other reserve service market options not presented here (or variations on the options, such as the variation discussed in section 6.2.3) that would be preferable? If so, why?	It is an oversight that the Directions Paper omitted mention of Delta's Rule Change Request 'NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services'[8],. This Capacity Commitment Mechanism model: a) directly addresses the issue of bringing back into the market capacity that is presently out-of-market, whether out-of-service generation or Demand side resources that are prepared to re-commit and then be dispatched in accordance with their energy bids; b) could operate alongside other mechanisms that might take longer to implement such as a real-time operational reserve market. The ability of fast-start plant to participate in either or both markets should lead to cost reductions for two reasons: 1. from more capability being offered in total; and 2. arbitrage between the two markets which should lead to convergence in value; c) proposes commitment timeframes that exclude no capacity type and is therefore technology neutral and because of that maximises the capability available for dispatch by the Market Operator; d) provides the basis for a relatively quick-to-implement market-based solution making it very suitable as an interim alternative to the current unsatisfactory over-use of market interventions.

[7] AEMC reference ERC0307, Introduction of ramping services | AEMC page 9
[8] AEMC reference ERC0306, Capacity commitment mechanism for system security and reliability services | AEMC

<table>
<tr><th>Supplementary AEMC Question</th><th>Delta Electricity Response</th></tr>
<tr><td>

EXECUTIVE SUMMARY

Consultation

…

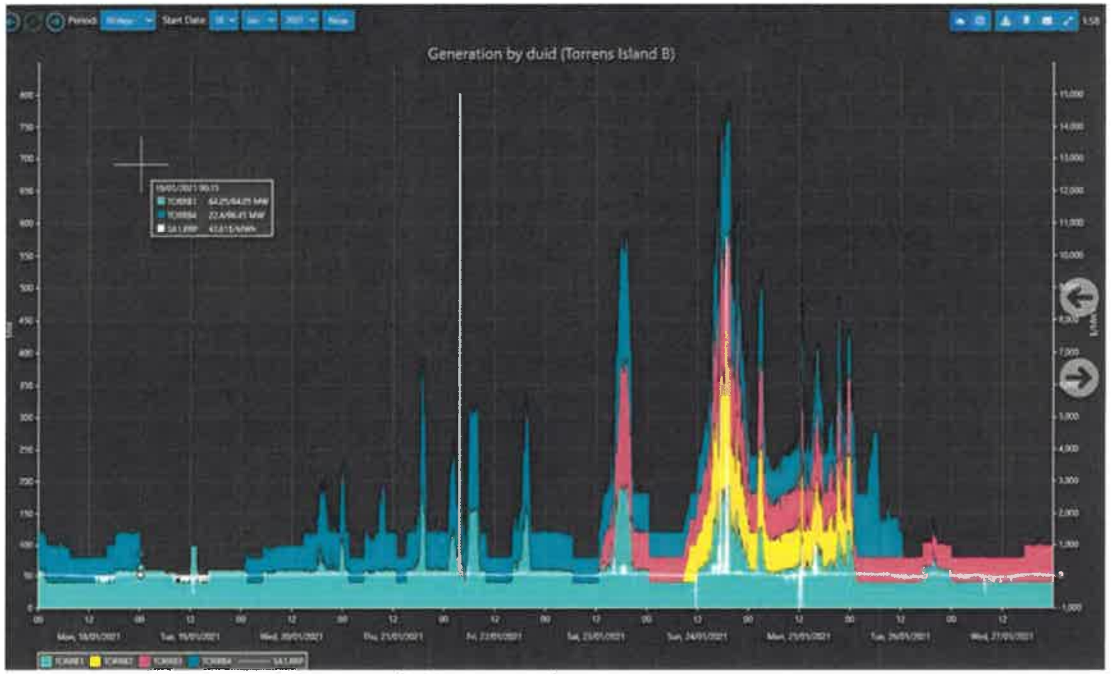
The AEMC invites stakeholder feedback on this paper. The Commission is particularly interested in stakeholder views on:

- the nature of the need for reserves and how meeting this need will evolve as the power system transforms
- whether there is a material need for a new reserve service to address this evolving need, and
- if so, what the appropriate high-level design of a new reserve service should be, including how this could interact with existing arrangements both in the wholesale energy spot and secondary contract markets.

Page v para 19

</td><td>

Delta is particularly concerned that the transition period to a high-VRE market exposes conventional thermal generation to strong pressures to periodically decommit due to negative/low prices during periods of high VRE output and that this market dynamic and its implications for Operating Reserve and system security has not been identified or considered in the analysis. The impact of a thermal power station retirement is relatively simple to assess. A changing pattern of in-service operation, like that occurring in SA. The chart shows Torrens Island B commitment and dispatch for a short period in January 2021. There is the obvious response to price spike but for extended periods unit are out of service on standby. The gas-fired boiler plant has a minimum load around 40MW and there is a much larger start times (ie up to 12 hours) than gas turbines. This plant is not unlike coal-fired plant and is a good indicator of possible future operation of coal fired plant during extend periods of low prices. Torrens Island plant provides the full range of essential services and is subject to direction by AEMO (AEMO NEM Event -Direction Report 12 to 16 September 2020, issued February 2021).

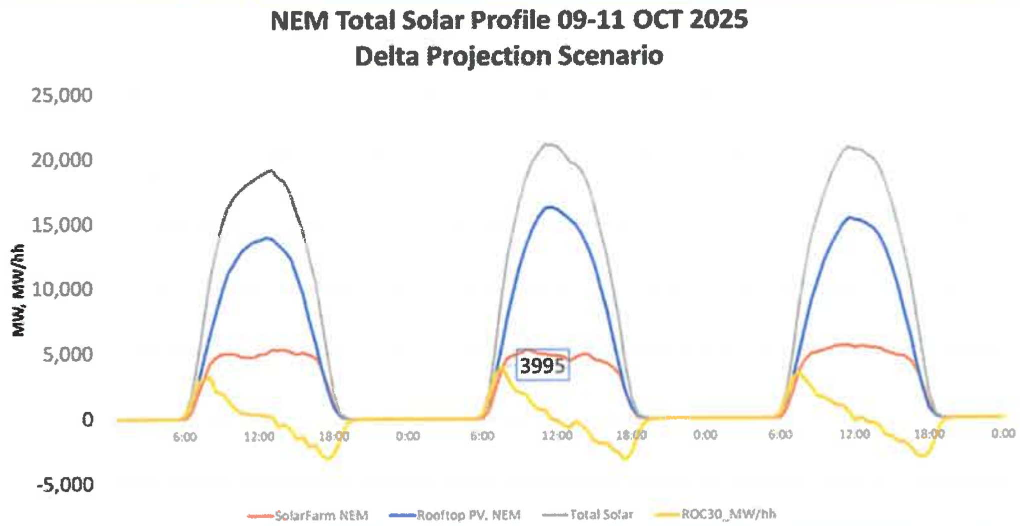


Source: NEOmobile screen shot (IES systems)

</td></tr>
</table>

Supplementary AEMC Question	Delta Electricity Response
	Directions are not a sustainable operating regime without returns from the energy market as generators can only recoup direction costs. Mechanisms must be available to the AEMO that will provide a market-based alternative to the market intervention by direction to generators to bring back into the market conventional thermal generators on stand-by. As noted in AEMO's Q3 2020 Quarterly Energy Dynamics report, it is thermal plant in SA on standby due to low prices that is being directed into service. The scale of the solar ramp (on top of wind variability) has not been adequately appreciated, especially considering new State-based schemes. The scale of the solar ramp is far in excess of and in addition to usual Operational Reserve needs and requires a dedicated solution.
4.2.1 Market Incentives Price signals in investment timeframes ... The nature of the price signal that investors respond to on an investment timescale, and that capacity responds to on an operational timescale, will change markedly when five-minute settlement is implemented in mid-2021. Indeed, this is likely to increase the value of flexibility as financial outcomes become linked more closely with 5-minute physical capabilities rather than 30-minute capabilities. The Commission is interested in stakeholder views on how this may change the analysis, and findings set out in this paper. Page 13, at bottom	Delta is sceptical that new investment occurs based on "5 minutes of economic sunshine". It would be anticipated that the greatest incentive to bring new capacity to markets will be from those entities to whom the cost is allocated. The dominant vertically integrated 'Gentailers' have mixed incentives – while they may be allocated the costs of provision of a service, they are also in a position to pass those costs on to customers and are therefore 'neutral'. 5-minute price volatility, in any of the NEM markets, represents a benefit to participants able to respond within that timeframe which becomes an allocation of benefits that is not technology-neutral and might be expected to be difficult for the Demand side to share in equitably.

Supplementary AEMC Question	Delta Electricity Response
Table 5.1: Reserves and expected ramping requirements There is no clear evidence to suggest that the current arrangements (that price the frequency and energy needs, but not the reserve need) will not be sufficient to provide sufficient reserves to meet *expected* ramping requirements on the power system. Table 5.1 summarises our views at this stage regarding expected ramping requirements. The Commission is interested in stakeholder views on this. Page 28	The Directions Paper underestimates the scale of ramping requirements to meet the recent high levels of Solar VRE capacity build, which has been more consistent with or exceeding AEMO's 'Step Change' scenario. A total (Rooftop plus Grid-scale) Solar Ramp by 2025 of around 24,000MW would be expected based on recent trends.This is so much greater than normal 'Operational Reserve' requirements that a dedicated service is required to affect the coordination of dispatchable capacity to meet this potentially daily challenge. The current arrangements were not designed for and do not plan to meet this challenge. Multi-GW ramps are to be expected: While Delta's analysis relied on 5-minute data, it was aggregated to 30-minute data for convenience and 15-minute maximum ramping is not quantified in Delta's model however the maximum 30-minute ramp expected for 2025 is +3995MW (raise) and -3592MW (lower) suggesting average 15-minute Ramps during those periods were around +2,000 (raise) and 1,800MW (lower). If these are the average of the maximum 30-minute ramps, you can be certain that the maximum 15-minute ramps will be a little higher. Further this data was based on a single year's (actual 2020) records and other years are likely to have more extreme outcomes. A 30-minute Raise requirement of +3995 MW equates to 133MW/min. It would require 27 large thermal units moving at a consistent 5MW/min. Even if 10MW/min could be sustained, 14 coal/gas units would need to have around 300MW of operating reserve available which is not possible, especially considering the +3,995MW ramp requirement is preceeded by a +3,291 ramp and followed by a +3,152MW ramp. Even if hydro/batteries could reliably deliver say 1000MW of reserve, the system is unlikely to be able to deal with this requirement and a properly structured market that incentivises the right capability is essential. Delta recognises that the above ramping example may include a component of unexpected solar ramping, however the following chart, suggests that the day on which the Solar ramp of +3995 MW/half-hour is projected to occur, 10 October, does not look too unusual.

Supplementary AEMC Question	Delta Electricity Response
	
Table 5.3: Reserves and unexpected ramping requirements Under the current arrangements, ensuring sufficient reserves are available to manage a rapid change in the nature of the security risks faced by the system may be costly. It may be prudent to consider whether more flexible and scalable arrangements may be better suited to a rapidly transforming power system. Table 5.3 summarises the Commission's views at this stage regarding unexpected ramping requirements. The Commission is interested in stakeholder views on this. Page 33	Delta views the 'unexpected' ramping requirements as the variability or uncertainty imposed on the expected ramping requirements. Uncertainty in ramping will scale with the Total Ramp – if the ramp has been underestimated then the uncertainty, in MW, of the ramp has also been underestimated. That uncertainty may be coincident with ramping from other sources including uncertainty in other VRE (in particular Wind), plant failures in conventional plant and variability in consumption. In summary, the quantum of uncertainty is likely to be higher due to the 'Step Change' Scenario or higher levels of growth in Solar VRE

Supplementary AEMC Question	Delta Electricity Response
6.1.5 Adapting system definitions The security of the power system is defined, in part, through its ability to withstand credible contingency events, which have historically been associated with events "that affect the power system in a way which would likely involve the failure or sudden and unexpected removal from operational service of a generating unit or transmission element." As the resource mix of the energy system transitions towards high penetration of VRE resources, there is potential to revisit the definition of 'contingency'. That is, the unforecast reduction of multiple GW of reduced wind generation over 15 minutes would not be considered a credible contingency event. Doing so may allow additional flexibility for the system operator to manage these events in the future. Such issues are being considered through the Enhancing operational resilience in relation to indistinct events rule change request from the COAG Energy Council, which the Commission initiated in December 2020. The Commission is interested in any feedback on the interaction between these two projects. Page 38	Different quanta of variability in VRE should be included as 'credible contingencies' with different likelihoods, similar to a single large conventional generator failure being a single contingency and loss of two such units being a double contingency. Projected 2025 Wind capacity, based on 2020 actuals would be expected to have 30-minute ramps of +1,400 (raise) and -1,500 (lower) (i.e. 15-minute ramps approximately +/-700MW) which have the potential to be coincident with the solar ramps described above. Delta is not in a position to assess how much of the observed solar or wind ramping may be unforecast, however it should follow that a scaling to greater levels of VRE should imply greater levels of MW forecast error. While one would usually assume that greater diversity in the <u>location</u> of solar and wind farms might reduce percentage forecast error, each State's designation of specific REZ areas may nullify the locational diversity benefit by concentrating wind/solar fluctuation risk.

Supplementary AEMC Question	Delta Electricity Response
6.2 Reserve services design options Each of these options will involve implementation costs. These costs will vary between options, perhaps substantially. Detailed input from AEMO will be required to provide estimates of implementation costs. It is likely that options that require the development of separate markets that are not integrated within existing arrangements for energy dispatch and financial settlement would have higher implementation costs. The Commission is interested in stakeholder views on the impact that the introduction of one of the below options would have on the existing spot market and associated ancillary services markets. Page 39	co-optimised operating reserve market/co-optimised availability market/ callable operating reserve market: Each NEM generation participant has an obligation to declare to AEMO the actual availability of each generator. Units that can be restarted within a timeframe of 30-minutes are effectively 'in-market' and are available to be dispatched according to their energy bids anyway. Delta is sceptical that any proposal that simply "rebadges" such capacity as 'reserve' or 'availability' creates value to the NEM in terms of increased reliability. What it does do is create additional revenue streams, which in Delta's understanding will be additional to the energy revenue stream. Energy costs may remain the same but total costs to the Customer are likely to rise with no reliability benefit. On the expectation that unit commitment of fast start plant is unlikely to change much under any of these three options, current FCAS markets are expected to be similar. The reserve services design focus should instead be on creating mechanisms that return to the market stand-by capacity that is currently not in-market as it is additional capacity that will create customer benefits from improved reliability. Ramping market A new 30-minute Ramping service, co-optimised with the energy and other FCAS markets as Delta proposed, was designed to address the challenge of balancing a large and growing solar ramp. The same capacity enabled for the 30-minute ramp can also be dispatched for energy or the other FCAS services in accordance with unit bids and the Dispatch engine minimising overall costs on the 5-minute dispatch cycle. Accordingly, this new service could also go much of the way to meeting operational demand requirements as well.

Supplementary AEMC Question	Delta Electricity Response
6.3 Consultation on options Each of the options described above has a range of benefits and drawbacks, including the extent to which the option: ▪ efficiently allocates resources to meet the power system needs for energy, FCAS and reserves ▪ provides sufficient certainty in meeting those power system needs ▪ impacts price signals in the energy and FCAS markets ▪ allows for efficient DER and demand side participation ▪ is easy to implement, and ▪ is capable of effective compliance. The AEMC seeks stakeholder feedback on the options presented. We are particularly interested in guidance on the appropriate trade-offs to be made between the factors outlined above, as well as the interactions with other areas of the NEM such as intervention mechanisms and the wholesale contract market. Page 48	Stand-by capacity brought to the market by a day-ahead mechanism brings back in to the market Operational Reserve as well as essential system services, yet this Directions Paper gives no consideration to this mechanism or how it might complement the other mechanisms proposed. AEMO concluded: *"Prioritise an out-of-market contracting, commitment mechanism for system strength and synchronous inertia* *.....This is why AEMO considers a contracting mechanism should be prioritised, something like the Delta Capacity Commitment Mechanism proposal or in the longer term an extended ahead optimisation.* *It should be noted the NEM already has a contract and commitment mechanism today with the system strength unit combinations and the directions and compensation framework. There are no disadvantages to improving on this with a contracting framework, a formal cost optimisation (such as the Unit Commitment for Security (UCS)), or both. Further developments, such as an ahead market may be considered by the ESB."* AEMO Submission to AEMC ERC0290 13 August 2020 page 21 As Delta has stated elsewhere, it believes that high levels of VRE will continue to drive the incidence of low and negative prices in the middle of the solar day: *"Negative wholesale electricity prices - During Q4 2020, negative and zero spot prices13 occurred in 7% of all trading intervals, surpassing the previous record set in Q3 2020 (4.6%), with calendar year 2020 averaging 4.4% compared to 1.7% in 2019. Negative spot prices were most prevalent in South Australia and Victoria, with both states reaching record quarterly levels. South Australia's spot prices were negative 17% of the time during Q4 2020, exceeding the previous quarterly of 10%, while Victoria reached a new record of 10%."* - AEMO QED Q4 2020 p12 This trend will reach the point where conventional thermal generation in other States are driven to decommit to minimise costs as has been the case in South Australia, potentially triggering shortfalls in essential system services such as synchronous inertia and system strength. Delta believes this market dynamic has not been considered in the ESB's Directions Paper but that it will result in, under the status quo, increasing frequency of market intervention to direct generators back into service for reliability and system security reasons.

Supplementary AEMC Question	Delta Electricity Response
	Delta believes that relying solely on fast start plant, which is the capacity effectively already "in-market", to provide reserves will not be adequate and that there will be years of transition where stand-by conventional generation will be needed to re-commit its capacity for reliability or system security and it is far better to have a market-based mechanism to secure these reserves on a competitive basis, such as Delta's proposed Capacity Commitment Mechanism rather than by market intervention.

DELTA ELECTRICITY'S PROPOSED RULE CHANGES – FAQ

18 February 2021

Introduction

Delta has proposed two system services rule changes to the AEMC:

- an ahead Capacity Commitment Mechanism: 'NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services'[1]; and
- new 30-minute Ramping Services: 'NEM Rule Change Request - New 30-minute FCAS Raise and Lower Services' [2]

Here are a number of Frequently Asked Questions in relation to these two rule changes:

QUESTION	RESPONSE
Capacity Commitment Mechanism	
Are Delta's proposals designed only to support coal and gas generators?	Delta owns and operates Vales Point Power Station, a large coal-fired power station in NSW. However, Vales Point's expected retirement date is 2029 and Delta's portfolio is an evolutionary phase where significant resources have been expended over the last few years on developing new generation projects including solar farms, utility-scale Battery Energy Storage Systems and pumped hydro energy storage systems. Over the long term, Delta's technology exposure is, like many other existing generation portfolios, transitioning to renewable and energy storage. Delta has identified what it believes are gaps in the current market mechanisms that, if left unaddressed, leave the power system more exposed to disruption and periods of unreliability.
Why is there concern about the supply essential system services?	The Market Operator needs to not only balance the supply of energy with the demand for energy at all times but needs to also ensure the reliability and security of the NEM and to do that the Market Operator needs an adequate supply of Essential System Services (ESS). Some ESS might need to be provided in a specific Region or even at a particular location within a Region. ESS includes operational reserve, voltage

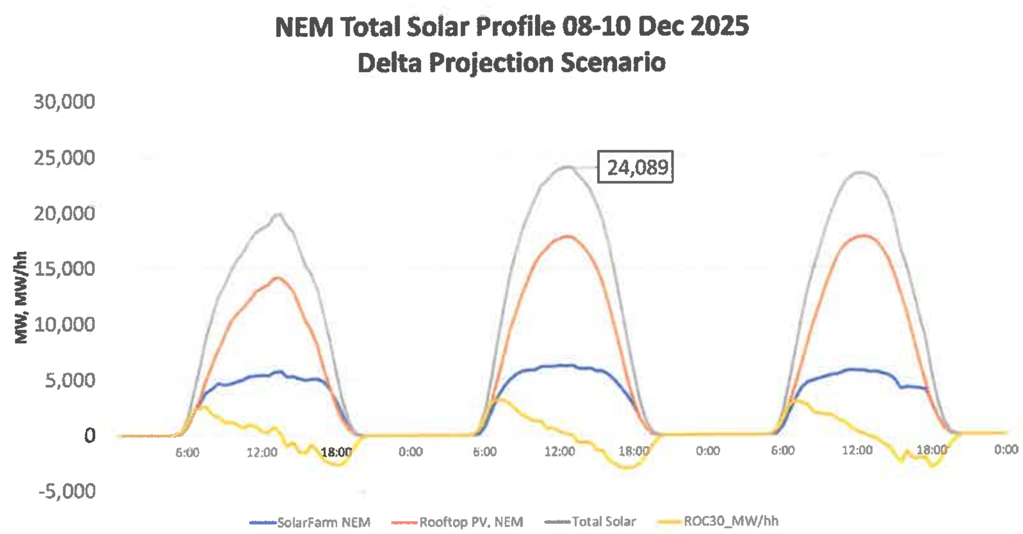
[1] AEMC reference ERC0306, Capacity commitment mechanism for system security and reliability services | AEMC

[2] AEMC reference ERC0307, Introduction of ramping services | AEMC

QUESTION	RESPONSE
Capacity Commitment Mechanism	
	support, system strength, inertia and frequency response. A good summary of Essential System Services is available in FTI's report to COAG's Energy Security Board (ESB)[3] The electricity system will depend on the system services that large synchronous generators provide for many years. Mechanisms will be required to ensure the adequacy of system services supply both in the transition period and in the long term. These system services have been effectively provided by traditional synchronous generators for free, which in the past has not been an issue when all competing generators have been similar technology and provide the same level of service (ie system service provision was competitively neutral). However, what was not previously a problem has become a problem as new capacity (typically Inverter Based Resources or IBR) does not, as presently installed, provide the equivalent level of system services. This means: a. the new IBR capacity is economically gaining a free-ride; and b. the system becomes less reliable as it relies on a shrinking base of system services supply from synchronous generators. See also the Technology Neutrality FAQ below
Technology neutrality: Are Delta's Capacity Commitment Mechanism proposals technology-neutral?	Delta fully agrees that the new generation technologies, as well as demand resources have significant technical potential to provide the same kind of services and indeed, in a renewable-only future must do so. Delta's submissions state this clearly, however, realistically it will nonetheless be years before the NEM will have adequate system service capability from IBR to substitute for the retiring synchronous generator fleet and that is why transitional arrangements are important.

[3] ESB: FTI's report to the ESB 'Essential System Services In The National Electricity Market' dated 14 August 2020 https://esb-post2025-market-design.aemc.gov.au/32572/1599207219-fti-final-report-essential-system-services-in-the-nem-4-september-2020.pdf

QUESTION	RESPONSE
Capacity Commitment Mechanism	
	Delta has stated clearly in both its submissions that any provider technology that is capable of delivering the service, either from the supply side or the demand side should be eligible. An important aspect of this is more efficient price-finding for services for example, in relation to operational reserve, there is no reason why Delta's day-ahead Capacity Commitment Mechanism could not operate alongside a 5-minute dispatch mechanism proposal. The market prices will signal when there is sufficient IBR system services capability such that the day-ahead mechanism is no longer required, at which time the day-ahead mechanism can be retired (although some demand-side resources may continue to need a degree of aheadness). One aspect of Delta's proposals that has been mistaken for technology non-neutrality is that Delta has explicitly stated that the Capacity Commitment Mechanism is, at the very least, a market-based alternative to the present mechanism of System Operator directions that has been widely seen as costly and inherently inefficient. The target of system operator directions has typically been thermal synchronous generation, consequently, under the market conditions that would have led to a System Operator direction, that technology would be expected to be committed under a capacity commitment mechanism. That is not technology-bias: that is the outcome that is occurring anyway under the Status Quo of System Operator direction and in no way limits participation by any other provider, whether on the supply side or on the Demand side.

QUESTION	RESPONSE
RAMPING SERVICES	
Why is a new Ramping Service necessary?	The issue being addressed by Delta's Ramping proposal is the emerging feature in the market of a very large solar profile (from both grid-scale solar farms and distributed rooftop solar systems) that needs to be accommodated by the balance of the system. Figure 2 from Delta's Rule Change Proposal[4] , updated to reflect levels of solar generation (both rooftop and grid-scale solar farms) consistent with recent projections by the CER, AEMO's reports on committed solar farm projects and in other respects AEMO's RIS "Step Change" scenario ('Delta Projection Scenario'), is shown below to illustrate the scale of the solar Ramp at each end of the solar day:  This FY2025 estimated maximum and minimum 30-minute Solar ramp rate in the modelled year are +3,995/ -3,592MW/30min (MW/hh - refer the purple trace). Large as these ramp rates are they are already being presaged by Calendar 2020 actual data which saw the maximum 30-minute ramp of aggregate NEM

[4] AEMC reference ERC0307, Introduction of ramping services | AEMC

QUESTION	RESPONSE
RAMPING SERVICES	
	Operational Demand as +2,587 and -3,136 MW/hh - equivalent to 4 Kogan Creek units per half-hour. The total ramp is a staggering 24,089MW, which is greater than the Calendar 2020 average NEM demand of 21,408MW. Taking into account the possible coincident ramping requirements in Consumption or wind generation, the 2025 Net Demand (Consumption less VRE) that is required to be served by synchronous plant is, based on actual 2020 dispatch patterns, estimated somewhat higher at +4,435/-3,102 MW/half-hour. The sustained ramping (over a period of 2-3 hours) is unprecedented historically and is orders of magnitude greater than the available MW in existing FCAS Raise and Lower services which were designed with market fluctuations over much shorter timeframes in mind, eg dealing with the trip of a large generating unit. This is the reason why Delta is convinced that a new dedicated service is required to deal with this issue. It should be noted that: 1. committed plant that can provide ramping services may already be loaded to levels covering a contracted position and may not have room to ramp up further; and 2. the ramping service is linked to the unit commitment rule change in that plant capable of providing ramping may otherwise be out of service and may need advance notice to commit in order to meet the ramping requirements of the NEM.
Who should pay for the new ramping services?	Delta has identified that ideally a 'Causer-Pays' principle be applied but recognised that identifying the causer may not be a simple process. The causer could be loss of a thermal unit, a fast rate of change of VRE or simply demand variability. The primary benefits of the rule changes are the reduction in the increasing cost of AEMO directions and the avoidance the market spiking to the maximum price. Accordingly, it may be more economically efficient to level the costs directly consumers noting the larger benefits consumers will gain from reduced directions and

QUESTION	RESPONSE
RAMPING SERVICES	
	lower electricity prices caused by VRE. Additionally, currently rooftop solar represents 66% of total solar energy production adding weight to the case to recover ramping costs from customers.
Is it synchronous generation that are inflexible and should bear the costs?	Refer AEMO: ""If conventional units (typically coal) decommit for long durations, particularly during high periods of VRE penetration, the dispatchable flexibility from the fleet will be reduced .... To operate the system successfully, flexibility must be able to be scheduled in the right direction at the right time. Flexibility must be harnessed in all parts of the power system by enhancing traditional sources, as well as embracing emerging sources." (AEMO Renewable Integration Study Appendix C 5.2.5 p.59.) The inflexibility that is present in this situation is that solar generation bids in at low 'Must Run' prices. The flexibility in this situation is that synchronous generation (including those of energy storage systems) are presently, and must in the future, ramp down to balance the rise in solar generation early each day and ramp up to balance the fall in solar generation at the end of each day.
Are Delta's Ramping proposals Technology Neutral?	Any synchronous generator can sustain a ramp over 30 minutes. It simply needs to assess whether that is preferable to bidding its capacity in the energy or other FCAS markets. The 30-minute ramping FCAS service is intended to be co-optimised with the other FCAS and energy markets and over the longer term generators will arbitrage their capacity between these markets until there is an equivalence in returns, that is how competition works. Even after legacy coal-fired plant is all retired, this service will still be needed, and the likely providers will be hydro and generators attached to storage systems like pumped-storage hydo, Battery Energy Storage Systems and hydrogen storage systems. Demand side capability should also be able to participate, with the daily cycle suggesting natural participation may come from loads like Hydrogen production and other liquified gas plant which would also benefit from the lower Spot prices co-incident with the solar cycle.

QUESTION	RESPONSE
RAMPING SERVICES	
How does the proposed Ramping Service fit with the other market services?	Delta's view is that: 1. services should be co-optimised to minimise costs of running the market where it is simple and economical to do so. 2. the 30-minute ramping service can do the 'heavy lifting' of bringing supply into balance with net demand with the existing FCAS raise and lower services then better able to fine-tune that balance. 3. Delta is of the view that without a ramping service the systemic, daily, large solar ramps that may be coincident with fluctuations due to weather and demand factors set the scene for extreme short-term (ie 5-minute) volatility to which some participants, such as end-users and demand Response, will be unable to respond. While some participants will argue that that volatility can be contracted away, Delta believes the better approach is to address the underlying physical supply-demand balance first and then deal with the residual volatility.