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31 August 2023

Shannon Culic
Operating Reserves Project Lead
Australian Energy Market Commission
Sydney NSW 2000

Dear Ms Culic,

Operating reserve market - Directions Paper

AEMO welcomes the opportunity to provide a submission to the AEMC's Directions Paper and provides comment in Attachment 1 of this submission on the Commission's decision not to proceed with an Operating Reserve.

AEMO sees emerging challenges with:

- Increasing forecast uncertainty, contributed to by factors including growing variable renewable energy (VRE) penetrations, weather, participant availability, commitment decisions, storage depth, and coordination of distributed energy resources.
- Increasing size and occurrence of ramping events.

These challenges were described in AEMO's Technical Advice of November 2022, and AEMO provides a selection of updated data and charts in Attachment 2 of this submission. This data supports the findings in the Technical Advice.

To maintain sufficient operating reserves to meet security and reliability obligations, AEMO may be forced to regularly intervene and activate the Reliability and Emergency Reserve Trader (RERT). AEMO is concerned with the growing number of market interventions required due to lack of reserves, noting the challenges associated with determining the latest time to intervene.

Attachment 1 also sets out that:

- AEMO is supportive of considerations to publish real-time state of charge aggregated by region.
- The AEMC should further consider proposals to procure regional, sub-regional FCAS, and operating reserves, in respect of planning for renewable energy zones.
- AEMO suggests the consideration of operating reserves should not be in isolation of other interdependent NEM reforms, in particular options to support demand-side participation in scheduling, and investment in firming capacity.

AEMO refers to its detailed Operating Reserves Technical Advice provided to AEMC in November 2022 for further detail. Should you wish to discuss any of the matters raised in this submission, please contact Kevin Ly, Group Manager – Reform Development & Insights kevin.ly@aemo.com.au.

Yours sincerely,

Violette Mouchaileh
Executive General Manager, Reform Delivery

Attachments:

1. Considerations and responses to consultation questions
2. Updated data

Attachment 1 - Considerations and responses to consultation questions

1. *Do you agree with the Commission's decision not to recommend the implementation of an operating reserve market?*

AEMO notes forecasting error is getting worse and beyond improving forecasting a market-based approach to incentivise reserves in the operational timeframe would minimise the need for short term intervention and better manage forecast error. Consistent with the Technical Advice, AEMO would consider the implementation of an Operating Reserve market with 1-4hr timeframes and strong compliance.

The decision to implement an Operating Reserve comes down to a view as to whether the market will adequately provide for reserves without support from the market operator instituting a direct market service. AEMO considers this is inherently debateable and questions the definitive stance of the Commission. We provide the following comments where AEMO considers the findings in the Directions Paper could be enhanced.

Incentives from operating reserve market vs energy market

Market participants face financial risks to make reserves available[1]

This is a correct assertion, but it's not an argument against an operating reserve. The real question is whether it is reasonably appropriate for a market operator to establish a clear requirement for operating reserves to improve the provision of these reserves, and to express the prevailing value of real time operating reserves to consumers through a demand curve. Further there are potential circumstances where a lack of information, or misaligned incentives, could give rise to occasions where the market does not provide for, or deploy effectively, adequate operating reserves. Additionally, a market reveals a price for operating reserves that all participants can respond to.

We therefore have no reason to suggest that a future characterised more by VRE forecast uncertainty would cause a breakdown in the relationship between financial risks and the commitment of reserves[2]

We know that the relationship between participant financial risks and reserves (i.e., the vulnerability of consumers to load shedding) is incomplete now (i.e., there are cases with low reserves and low prices). With greater VRE uncertainty, the issue is that unexpected changes in reserves can be of larger magnitude, and therefore the consequences of their incomplete relationship with financial risks are potentially more severe.

Assessment of whether trends in reserve provision will be sufficient to meet growing needs

The fact that developers and investors are willing to sink these costs for potential investments in very flexible capacity, based on the incentives present under current market frameworks, is a significant sign that the NEM is more likely to evolve toward a system with much higher levels of capacity that is very flexible over shorter durations[3]*.*

The question is not whether flexibility is increasing, the question is whether the increase in flexibility is likely to be commensurate with the growing need for flexibility.

Modelling

These results should be read in light of the assumptions of the modelling, principally that the model assumes the system is largely intact and does not include interconnection, demand response or the impact of participant self-commitment decisions (whether rational decisions to manage risks or other less explicable decisions). These assumptions are viewed as imposing a degree of conservatism on

[1] AEMC, Operating reserve market directions paper, Directions Paper, 3 August 2023, section 4.1.2, p32
[2] AEMC, Operating reserve market directions paper, Directions Paper, 3 August 2023, section 4.3.1, p43
[3] AEMC, Operating reserve market directions paper, Directions Paper, 3 August 2023, section 4.1.4, p37

the model's outputs. If these assumptions were relaxed, it is likely that the ability of the future fleet to manage increasing reserves needs would be still greater, which would further reinforce the conclusions drawn[4].

This point is invalid. If a different demand trace (i.e. higher demand) was chosen, the benefit of all of the mentioned sources of ramping capacity could have been completely offset. The demand traces were chosen specifically to drive meaningful insights from the model, by being high enough to show a system with scarce reserves, but not so high that the real issue was a fundamental scarcity of capacity.

2. *Is there merit pursuing the two additional incremental improvements, including formalising these in the Rules framework?*

AEMO sees merit in pursuing the publication information of state-of-charge of batteries, aggregated by region, as a first step towards broader consideration of energy-limited plant.

AEMO is currently considering the merits of procurement of FCAS at regional or sub-regional levels alongside broader consideration of system planning and contingency sizes and suggests this issue should be investigated in further detail alongside planning requirements for Renewable Energy Zones.

Section 5.4 of the Directions Paper discusses the procurement of regional FCAS quantities. The AEMC seems broadly positive towards this development, yet the problems that regional or sub-regional FCAS may solve are not properly explained. AEMO takes this opportunity to set out its understanding of the potential opportunities for the procurement of local requirements of FCAS and requirements for reserves.

N-1-resecure

Clause 4.2.6(a) requires AEMO to maintain the power system such that is and will remain in a secure operating state. The system is secure if, under clause 4.2.4(a)(1), it is satisfactory, and, under clause 4.2.4(a)(2), will return to satisfactory following credible contingency. Colloquially this is known as "N-1".

Clause 4.2.6(b),(1) requires AEMO following a contingency (even non-credible) to return the system to secure as soon as practicable, or in any event, within 30 mins. Colloquially this is known and "N-1-resecure".

Network planners are presently considering how to size connections for Renewable Energy Zones (REZ). When considering a double circuit connection, the network is planned to ensure the pre-contingent flow is limited, (this being the limit on the REZ generation), considering the following:

- Secure loading of the remaining circuit – this is either limited by the available FCAS (e.g., the 750MW size of the largest generator contingency today) or the applicable rating of a circuit – this is the post-contingent flow; and
- Adequacy of reserves available (on the wider grid) if a circuit trips and the REZ generation reduces to the secure loading of the remaining circuit (as above).

Powerlink has raised the question whether sub-regional FCAS, regional FCAS and operating reserves could be used to optimise pre-contingent flows for REZ connections.

The need for operating reserves relates to the N-1-resecure requirement, because planners have observed, absent building another circuit, the reserves available may be the limiting factor to the pre-contingent flow.

Powerlink also suggest FCAS may be required on a pre-contingent basis if the generation within the REZ reduces output rapidly. The relationship between 5-minute dispatch, available reserves,

[4] AEMC, Operating reserve market directions paper, Directions Paper, 3 August 2023, section 4.1.5, p39

FCAS, the way the REZ generation is expected to “runback”, and the applicable short-term rating of the circuit needs much more investigation. Importantly the N-1-resecuring requirement, which is the need for operating reserves within 30 minutes, must be in scope. Additionally, the location of reserves, with implications for the treatment of interconnectors would need to be in scope. If there is any requirement to shed load or exercise RERT to manage the contingency and support the pre-contingent flow, it is unlikely to be economic and AEMO would consider out of scope.

AEMO would suggest this be considered in conjunction with the other pending rule proposals that aim to co-optimise the largest contingency and implement marginal pricing for FCAS cost allocation through “runway pricing”. Without better cost allocation processes any proposal to co-optimise contingencies with available FCAS is unlikely to be successful. It is possible a REZ could be included in these proposals.

Voltage

If contingency FCAS is concentrated in certain locations, as tends to happen because FCAS in states with low reserve conditions is too expensive, a credible contingency could result in rapid changes in active power and voltages at different points on the network. This could be better managed by regional or sub-regional procurement of FCAS for example, at times having a minimum amount of contingency FCAS procured at points on the network.

3. *Are there any other incremental improvements that should be pursued in the absence of an operating reserve market being implemented?*

AEMO notes several improvements are currently being pursued including through the redevelopment of PASA, Project Fusion, the Engineering Framework Priority Actions and the GPSRR. The fundamental question is whether we need additional signals for reserves beyond the “emergency mechanism” of RERT – incremental improvements do not resolve this question, and are sensible to implement for their own reasons.

Attachment 2 - Updated data

As an aside to AEMO's position on the merits of an operating reserve product discussed in the body of this submission, this appendix provides an update on trends that have motivated the consideration of an Operating Reserve product through the life of this reform. The update follows on from AEMO's operating reserve technical advice provided in November 2022.

This appendix includes data on operational forecasting errors and reserve-price correlations during LOR periods. Section A.2.1 shows that forecast error continues to increase. This is significant because it necessitates greater fleet responsiveness. For a given level of reserves, the fleet is more vulnerable as forecast errors grow. Section A.2.2 demonstrates that periods of low reserves do not necessarily result in high energy prices; an observation that has endured since the introduction of 5-minute settlement (1 October 2021). This means that energy prices are not signalling the growing vulnerability caused by rising forecast errors to the market. This combination of trends motivates consideration of an Operating Reserve product.

A2.1 Forecast error

Definitions

- Operational demand[5] is demand to be met by the scheduled and semi-scheduled fleet, and non-scheduled generators >30MW. It does not include demand that is met by rooftop PV, so errors in rooftop PV forecast **do** impact operational demand forecast accuracy.
- 'Net load' is not a defined term in AEMO's market systems. However, in the charts below, net load refers to operational demand less utility scale VRE (i.e. the sum of semi-scheduled and non-scheduled generation). As operational demand is affected by rooftop PV output, then net load forecast error is the sum of coincident errors across utility scale VRE, rooftop PV[6] and demand. Net load must be met by the scheduled generating fleet, so net load error measures how much the fleet must respond to unexpected changes in the supply-demand balance.

Data

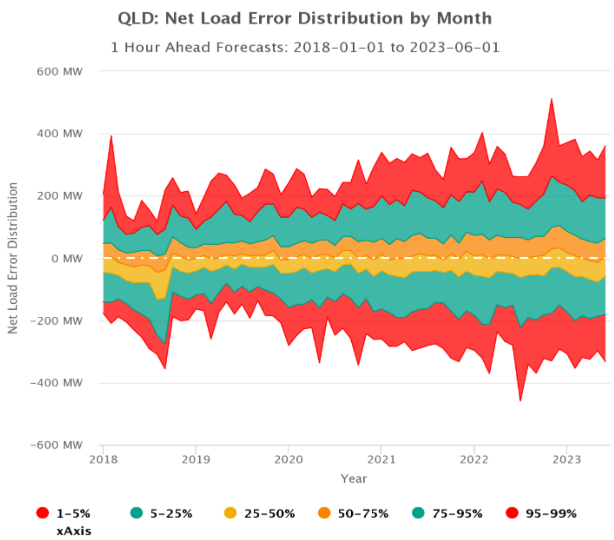


Figure 1

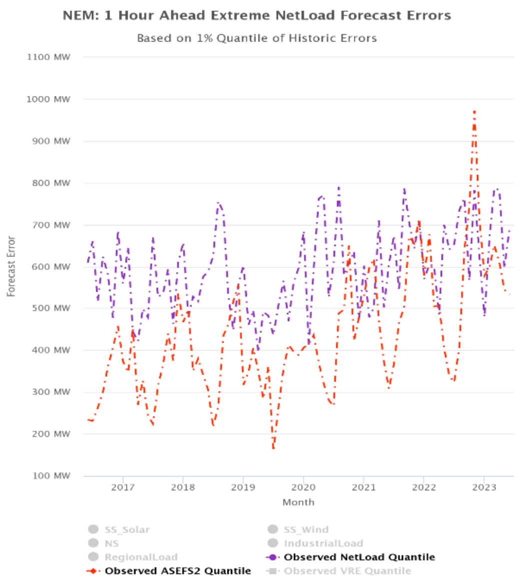
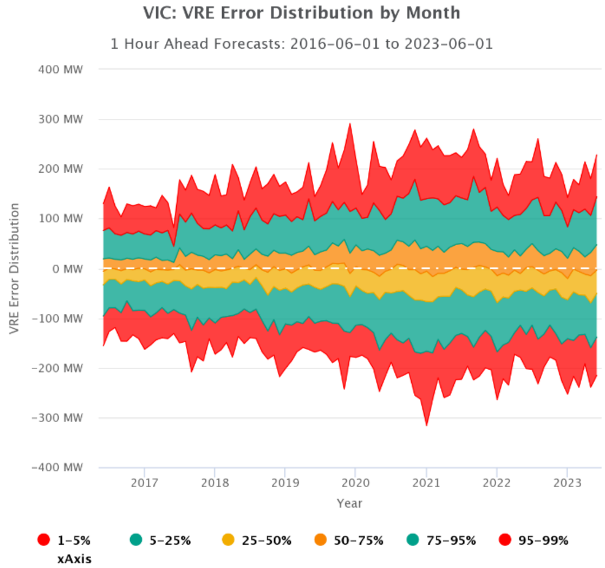


Figure 2

[5] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf
[6] Or 'ASEFS2', a reference to AEMO's rooftop PV forecasting system



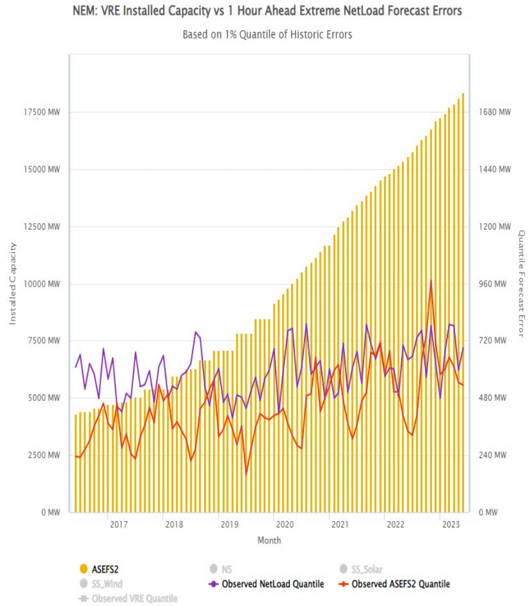


Figure 3

Figure 4

Observations

- Across the NEM, net load error is increasing. For example, Figure 1 shows that the 1st percentile errors on a 1-hr timeframe in Queensland have increased from ~200MW in 2018 to >300MW in 2023.
- Where historically net load errors have been driven by other factors (typically demand forecast error), rooftop PV forecast error is emerging as the largest source of forecast error. Figure 2 shows that between 2016 and 2020, the 1st percentile net load error (purple) was typically above the 1st percentile rooftop PV error (red). However, from mid-2020 to the present day, rooftop PV error has risen and the gap between it and net load error is now minimal. This suggests that the NEM has crossed a threshold whereby rooftop PV error is setting the net load error. The upward trend in rooftop PV error is therefore likely to drive up the total net load error over time.
- AEMO notes that utility-scale VRE forecast error is not increasing at the same rate as rooftop PV error, and has been relatively stable for the last couple of years. Figure 3 demonstrates this in Victoria, showing growth in (utility-scale) VRE in the later part of the 2010s, but no significant growth since 2021.
- AEMO notes that, though net load error has increased substantially, it has not increased at the same rate as VRE installations. Figure 4 includes the same data as Figure 2, but also overlays the growth in rooftop PV installed capacity for reference. The *relatively* subdued growth in net load error could in principle be caused by improvements in forecasting technique, benefits of geographic diversity of the renewable fleet or a range of other factors. AEMO has not carried out attribution analysis to determine which factors are most significant.

A2.2 – Reserve-price correlation during LOR periods

Definitions

These graphs show the 5-minute prices and corresponding reserve levels for dispatch intervals during LOR events. Data is presented from October 2021, when 5-minute settlement was enacted. The dashed red lines in each figure are the median LOR2 and LOR1 thresholds across the sample. These lines are intended to be indicative. Specific observations may, for example, show reserves lower than the LOR2 threshold line, but actually correspond to LOR1 cases where the LOR1 threshold was lower than the median value.

Data from the Winter Crisis and Market Suspension Event of 2022 has been omitted (that is any dispatch intervals between 12th (commencement of administered pricing) and 24th June 2022 inclusive).

Data

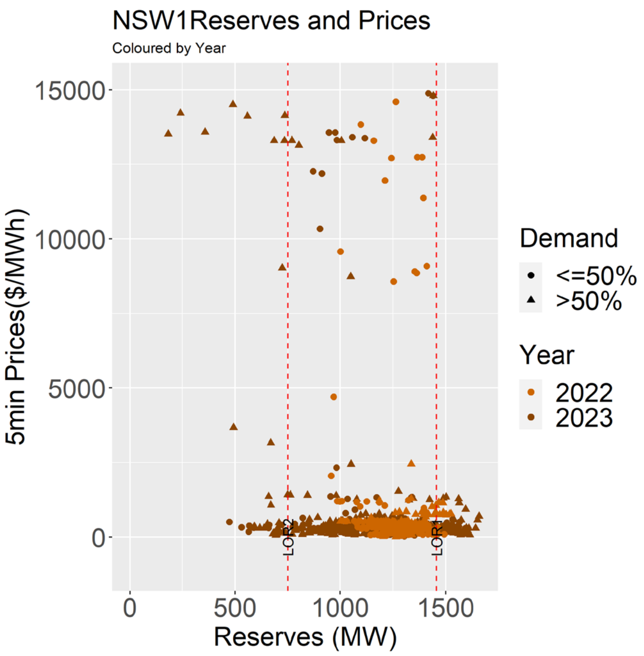


Figure 5

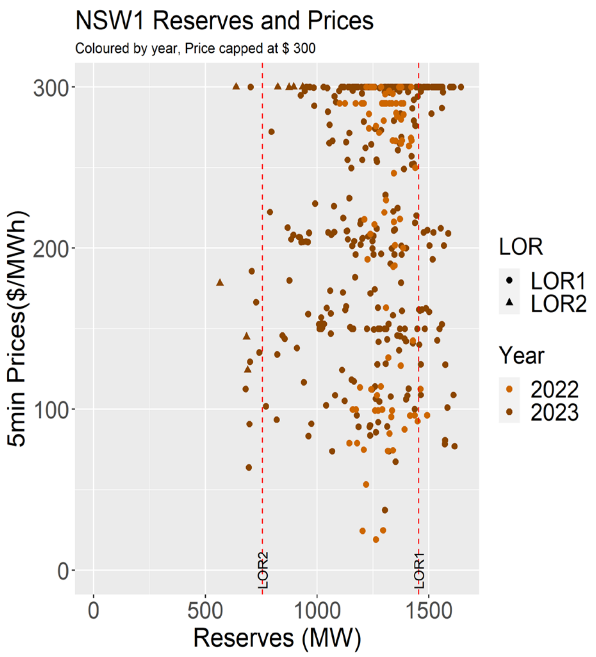


Figure 6

Figures 5 and 6 show that, in NSW, there are frequent periods of low reserves and low prices, including LOR2 periods with prices less than $300/MWh. Noting that the winter crisis is excluded from the dataset, these charts suggest greater vulnerability in 2023 than 2022 in NSW during periods of normal energy spot market operation.

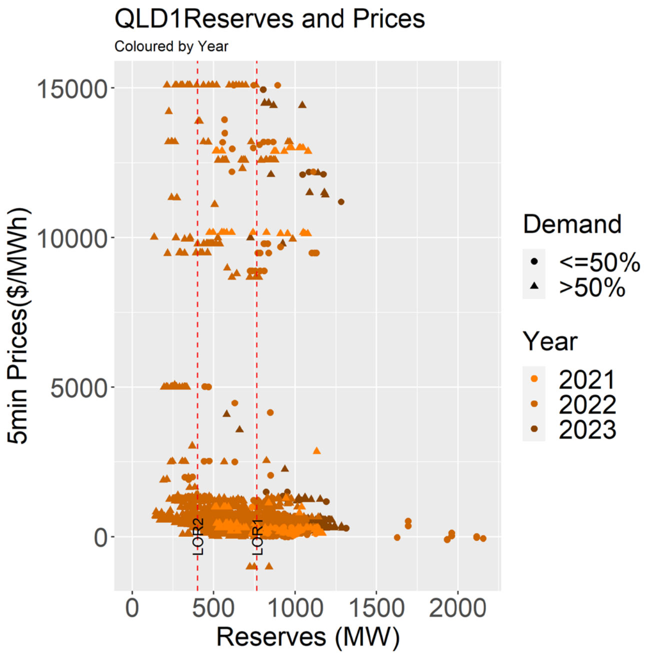


Figure 7

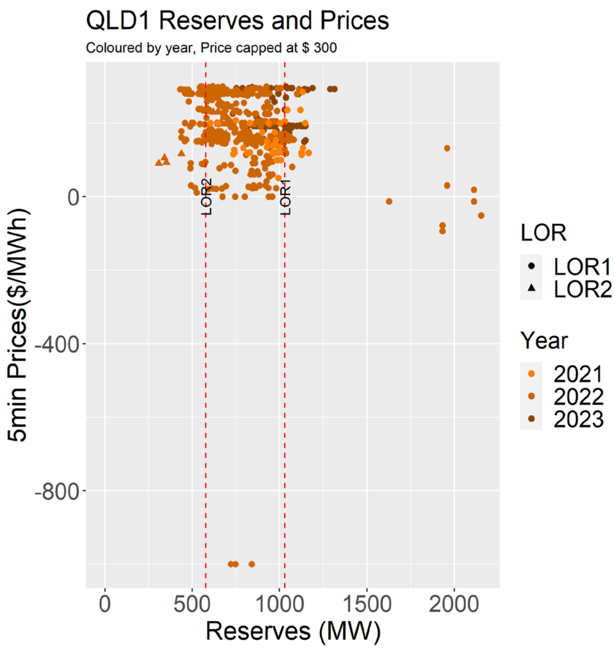


Figure 8

Figures 7 and 8 show that Queensland has experienced particularly low and even negative energy prices at times of low reserves. In contrast to NSW, these periods were most frequent in 2022.

Implications

The existence of low prices during periods of low reserves highlights that spot market prices, nor secondary contracts, are not always providing sufficient incentive for resources to be online and available during times of low reserve. This data is particularly relevant for the consideration of an Operating Reserve.

There are a significant number of intervals, even in the short period of time since 5MS, in both QLD and NSW with low reserves (<LOR1), low demand (<50th percentile – circle markers), and suppressed prices (significantly below MPC). Periods with low demand, low reserves, and high prices also warrant further investigation and suggest commercial availability may not always be responding at times of low reserves.

As the system transitions towards higher penetration of renewables, low energy prices during middle of day are a signal for thermal plant to decommit or to not operate at all for multiple days, reducing the amount of operating reserve provided to the system. Some resources incur a cost to provide operating reserve currently, but do not get explicitly rewarded for doing so.