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Response to Energy Security Board's Post 2025 Market Design Options Papers

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Dr Kerry Schott

Chair

Energy Security Board

Lodged electronically

Dear Dr Schott,

Re: Post 2025 Market Design Options Papers

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission in response to the Energy Security Board (ESB) regarding its Options paper on potential market design options for the National Electricity Market (NEM) post 2025.

About us

The UNSW Collaboration on Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from a range of faculties, working alongside a number of Australian and international partners. CEEM's research focuses on the challenges and opportunities of clean energy transition within market-oriented electricity industries. Effective and efficient renewable energy integration is key to achieving such energy transition and CEEM researchers have been exploring the opportunities and challenges of market design and policy frameworks for renewable generation for the past two decades. More details of this work can be found at the Collaboration website. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please feel free to contact Associate Professor Iain MacGill, Joint Director of the Collaboration (i.macgill@unsw.edu.au) and/or Dr Anna Bruce, CEEM's Engineering Research Coordinator (a.bruce@unsw.edu.au) regarding this submission or for other CEEM matters.

Our approach to this submission

Our submission addresses the Options papers' questions within the Essential System Services, Scheduling and Ahead Mechanisms reform pathway that concern the implementation of an operating reserve or ramping service in the NEM. We first discuss the various purposes that an operating reserve service might serve in the NEM. We then present modelling and quantitative analysis that has been undertaken by researchers in CEEM to explore:

1. The characteristics of in-market reserves both now and into the near future, with a particular focus on the horizon, or time-to-realisation, of these reserves and typical periods of reserve scarcity.
2. The impact of aggregate variability and uncertainty on intra-dispatch ramping requirements as utility-scale solar PV capacity grows over the next two decades in the NEM.

We also emphasise the need to better characterise and quantify the need for an operating reserve service in the NEM, particularly given that see it as likely that the costs of such a service will be paid by consumers.

While time did not permit a more complete submission, we would of course be very happy and interested to discuss our views on all reform pathways, and the associated questions for consultation, if that is of interest to the ESB.

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Questions from Part A

Q26: How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?

I. *Capabilities of operating reserves*

Before addressing how an operating reserve service might fit within a framework for essential system services in the NEM, it is important to consider what capabilities operating reserves may have.

A potential operating reserves service is defined by how service-wide characteristics leverage resource-specific capabilities. As discussed in our response to the AEMC's *Reserve services in the National Electricity Market Directions Paper,* resources that would offer an operating reserve service are essentially providing a combination of two distinct but somewhat interrelated resource-specific capabilities[1]:

1. *Ramping capability* that enables resources to meet unanticipated, anticipated or all ramping requirements. The *horizons* over which ramping may be required include within a dispatch interval, in the next dispatch interval (i.e. 5 minutes), or over or after a number of successive dispatch intervals (e.g. over the next 30 minutes or with a 30 minute notice period).
2. *Reserve capacity* that is either online or offline and *realisable*. The latter means that reserve capacity can be converted into a commensurate energy response within the reserve horizon. While this is dependent on the ramping capability of the resource, it also requires resources to maintain headroom or footroom.

Beyond resource-specific capabilities, the characteristics of an operating reserve service depend on the service specification (which might specify a reserve horizon), procurement quantities and constraints, and its interaction with energy, frequency control and other system services. Together, these capabilities and characteristics define what an operating reserve service can offer and therefore what it should be able to achieve.

II. *The purpose of an operating reserve service*

The required capabilities and characteristics of an operating reserve service and, more broadly, where operating reserves fit within the NEM's framework for essential system services depend on the purpose of an operating reserve service. Several purposes have been discussed, both within the AEMC's *Directions Paper* and in response to it:

- The AEMC considered that an operating reserve service could be needed to address both expected and unexpected changes in net demand. However, they concluded that the need for operating reserves to meet unexpected changes was more material[2]. From an efficiency perspective, a short reserve horizon (in the order to 5-10 minutes) would be preferable for an operating reserve service that addresses unexpected changes in net demand, as forecast and other power system uncertainties are likely to decrease as the system approaches real-time[3].

[1] Abhijith Prakash et al., "Response to Reserve Services in the National Electricity Market Directions Paper," 2021, p11

[2] Energy Security Board, "Post 2025 Market Design Options – A Paper for Consultation: Part A," 2021, p50.

[3] Australian Energy Market Operator, "Renewable Integration Study Appendix C : Managing Variability and Uncertainty," 2020, p37–38.

Such a service would sit at the intersection between system security and reliability and ensure that the supply-demand balance can be achieved whilst relieving any deployed FCAS (we note that the ESB considers that capacity should not be simultaneously allocated to FCAS and operating reserves, and we agree that this restriction must be in place to ensure that deployed FCAS can be relieved[4]).

- In their submission to the *Directions* Paper, AEMO suggested that an operating reserve service should also reduce the need for system operator intervention based on Lack of Reserve (LOR) levels. To achieve this, AEMO has supported a reserve horizon of 30+ minutes. Such a horizon provides AEMO with certainty around reserve availability ahead of time and therefore provides buffer time between reserve procurement and the latest time to intervene should a LOR 2 or 3 condition materialise[5]. The primary benefit of this type of operating service is that it could reduce energy market distortion that may arise from AEMO intervening in the market. The secondary reliability and security benefits of this type of operating reserve may be smaller than a shorter reserve horizon due to “hysteresis” between the system state and reserve procurement and response.
- In our submission to the *Directions Paper*, we discussed the possibility that with growing variable renewable energy penetrations in the NEM, intra-dispatch ramping capability may be needed to manage a potential increase in ramp forecast uncertainty[6]. Should ramp forecast uncertainty become a material issue during a dispatch interval, existing frequency control arrangements would likely lead to primary frequency response and regulation FCAS ramping to address a growing error between the forecast and actual supply-demand balance. If the total error exceeds the available volumes of these services or if the ramp error grows at a rate greater than the ramp rates of frequency control services, the frequency stability of the system may be at risk. Intra-dispatch intervals could be addressed through existing frequency control services (though this requires a review of the purpose and capabilities of existing and emerging FCAS) or through a separate intra-dispatch ramping or load-following service (though it is unclear how such a service would interact with ramping “procured” through the dispatch process).

Since addressing each of these purposes is likely to require ramping capabilities and reserve capacity of different magnitudes over different horizons, further analysis is needed to better quantify which, if any, of these needs and purposes are material in the NEM today or in the future[7].

Researchers from CEEM have begun to explore and quantify some of the changes in resource capabilities and system needs as variable renewable energy penetrations increase in the NEM. In particular, we present modelling in this submission that attempts to quantify realisable in-market operating reserves across different timeframes for two NEM regions throughout 2020 and 2025 and the ramp capability required to address intra-dispatch uncertainty and variability as solar PV capacity in the NEM increases towards approximately 26.7 GW by 2043 (which corresponds to the Neutral case from AEMO’s 2018 ISP).

[4] Energy Security Board, “Post 2025 Market Design Options – A Paper for Consultation: Part B,” 2021, p40.

[5] Australian Energy Market Operator, “Submission to the AEMC’s Directions Paper – Reserve Products in the NEM,” 2021, p6, 21–22.

[6] Prakash et al., “Response to Reserve Services in the National Electricity Market Directions Paper,” p16.

[7] Prakash et al., “Response to Reserve Services in the National Electricity Market Directions Paper,” p7.

i. Realisable reserves across reserve horizons

Using Energy Exemplar's PLEXOS Market Simulation Software, researchers from CEEM have modelled realisable reserve capacities across several reserve horizons (i.e. 1 minute to 1 hour) in two NEM regions, New South Wales (NSW) and South Australia (SA), across 2020 and across 2025 (modified generation mix scenarios for 2025 based on AEMO's 2020 ISP 'Central' and 'Step-Change' scenarios were modelled, with the latter including the entry of Snowy 2.0 to the NEM). NSW and SA were modelled as self-contained (i.e. without interconnection), which provides an indication of realisable reserves in situations where regional constraints or interconnector limits do not permit operating reserves to be obtained from adjacent regions. Based on the results of economic dispatch across each modelled year and operational assumptions for each generation type[8], realisable reserve capacities for each reserve horizon were calculated.

Figure 1 shows the average realisable reserve capacity available across various reserve horizons for a given hour of the day based on modelled outcomes for NSW and SA in 2020 and in 2025. While the modelled outcomes are sensitive to operational assumptions for each generation technology (see Appendix A: Realisable reserves over different reserve horizons), the model suggests that reserve capacity may be scarcer during evening peaks. Furthermore, the model suggests that realisable reserve capacity might be "banded" or "clustered" based on the reserve horizon. For example, in the NSW 2020 and NSW 2025 'Central' scenarios, the amount of realisable reserve capacity is similar across reserve horizons from 2 minutes to 10 minutes. Similarly, for SA across all scenarios, the amount of realisable reserve capacity is similar across reserve horizons from 5 minutes to 1 hours. We note that the difference between the analysis presented in this submission and Figure 9 of Part B of the ESB's *Options Paper*[9] is that this analysis considers operating reserve that is available after generation is dispatched to meet demand given operational constraints (e.g. start times and minimum stable levels) and is therefore more indicative of actual reserve availability.

However, average realisable capacities do not necessarily quantify the availability of operating reserves when they are scarce and thus when they are most needed. To further investigate these periods, the 1st and 0.04th percentile of realisable capacity was calculated for each 5-minute window in a day across the modelled year (e.g. dispatch interval ending 13:10 across all days in the modelled year)[10]. The 1st percentile represents the bottom 1% of realisable reserve capacity during the year at that time of day, and hence provides a picture of a 1-in-100 day of low reserves. Further lowering the percentile analysed means that the probability of occurrence of such low reserves begins to decrease but the probability of unserved energy begins to increase. A percentile of 0.04, which corresponds to the bottom 0.04% of realisable reserve capacity, was chosen to investigate how realisable reserve capacity changes as the probability of occurrence begins to approach the NEM's reliability standards (no more than 0.002% of forecast customer demand unmet per year) and unserved energy standards (no more than 0.0006% unserved energy in any region per year), though we note that the calculated percentile is a proportion of all dispatch intervals in a year whereas the NEM's reliability and unserved standards correspond to a proportion of forecast demand in a year.

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[8] A detailed summary of the modelling and assumptions are included in Appendix A: Realisable reserves over different reserve horizons

[9] Energy Security Board, "Post 2025 Market Design Options – A Paper for Consultation: Part B," p37.

[10] Put another way, the 1st percentile means that across the year, 99% of the realisable reserve capacity for that time of day across the period of interest (in this case, a year) is greater than the values shown.

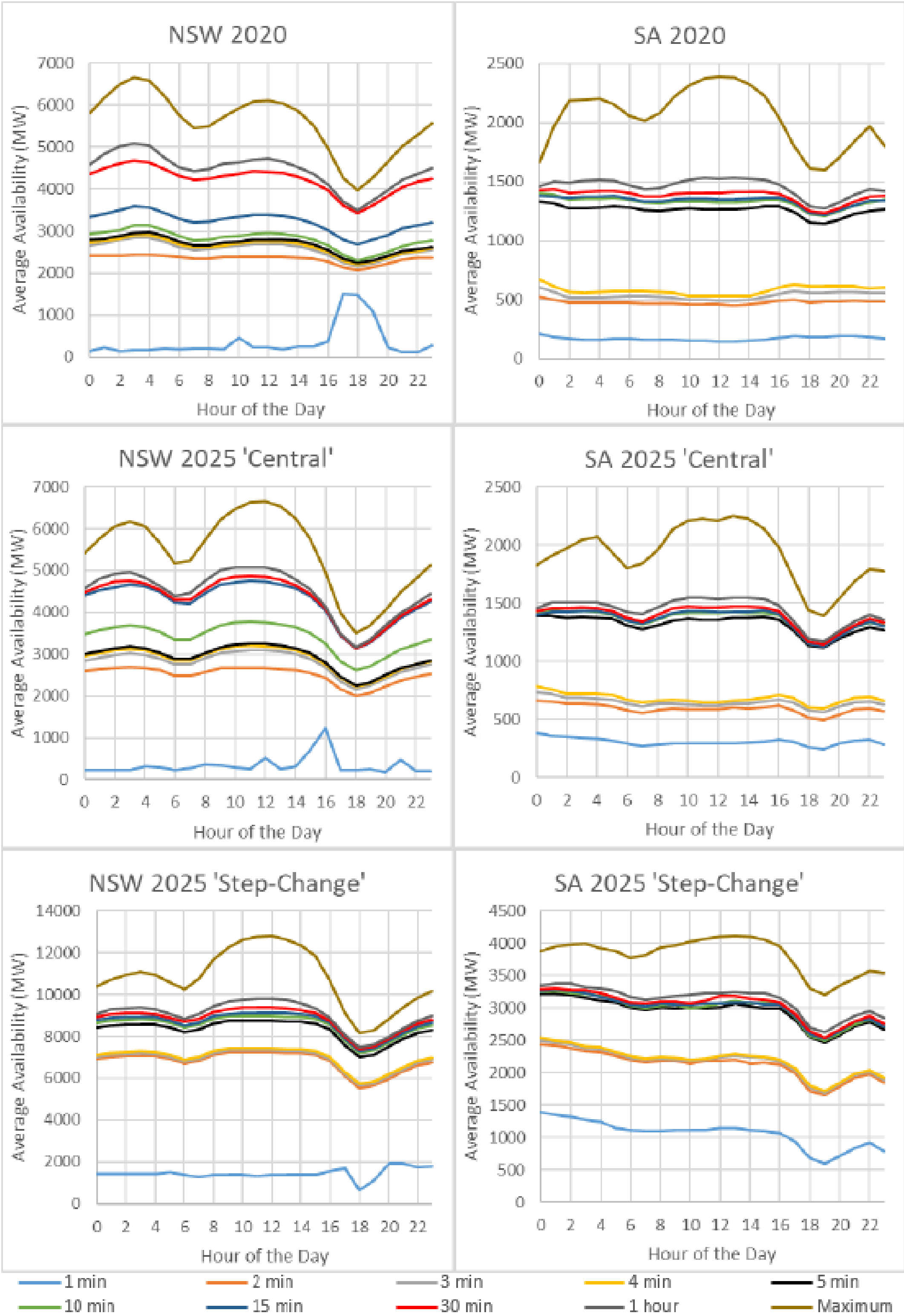


Figure 1: Average realisable reserve capacities (in MW) for a particular hour of day across each modelled scenario and year. Each coloured line denotes a different reserve horizon. For example, in the NSW 2025 'Step Change' chart, approximately 2000 MW of operating reserve can be realised within 1 minute at 8PM on average across the year.

Figure 2 shows the the 1st and 0.04th percentile of realisable capacity calculated for each 5-minute window in a day across 2020 for NSW and 2025 in SA, based on a modified 'Step-Change' generation mix (all modelled scenarios and regions are included in Appendix B: 1% and 0.04% Lowest Realisable Reserve Capacity for NSW and SA in 2020 and 2025). While Figure 2 shows that realisable reserve capacity remains "banded" or "clustered" based on reserve horizons during most of the day, evening peaks see capacity with reserve horizons between 5 minutes to an hour converge as total realisable reserve capacity becomes scarcer. This is likely due to relatively inflexible but cheaper capacity being ramped up through dispatch to meet expected changes in scheduled demand, leaving more flexible but more expensive capacity as realisable operating reserve capacity across both shorter and longer reserve horizons.

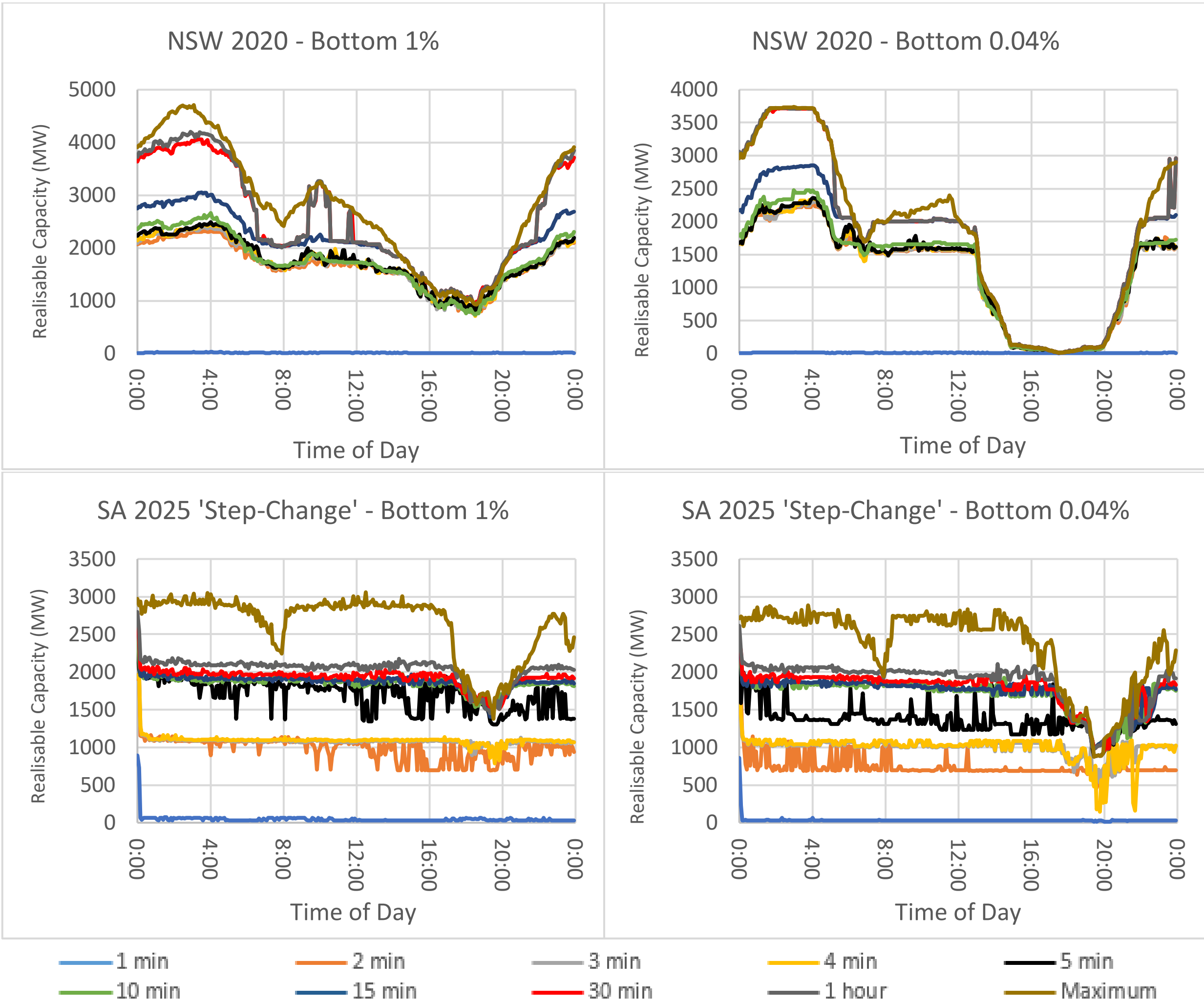


Figure 2: Bottom 1% and 0.04% of realisable reserve capacity for each 5-minute period in a day across the scenario year. Note that the percentile has been calculated for each dispatch interval and that they are not necessarily coincident (i.e. bottom 1% realisable capacity values at 13:10 may not occur on the same day as bottom 1% realisable capacity values at 13:15).

These modelled outcomes suggests that at times of operating reserve scarcity both now and into the near future, there may not be a material difference between the realisable reserve capacity that can be obtained for a horizon of 5 minutes, for a horizon of 30 minutes and horizons greater than 30 minutes. As such, provision of operating reserves at these times of scarcity may come from more flexible resources that can provide a response within 5 minutes, regardless of whether the service specification requires this response. This suggests that concerns about limited providers for operating reserves are not exclusive to a short reserve horizon service specification (e.g. 5 minutes, as in the co-optimised operating reserve market design option proposed by the AEMC) during expected periods of operating reserve scarcity.

While this analysis does not model these NEM regions and operational assumptions and constraints to the level of detail that AEMO is capable of, we see value in the ESB and AEMO modelling realisable reserve capacity across different reserve horizons in greater detail. Beyond exploring when a material need for an operating reserve service may arise, there is outstanding work to be done to compare and potentially quantify the benefits of a longer reserve horizon (30+ minutes), with a purpose of reducing interventions in the market, relative to the benefits of a shorter reserve horizon (e.g. 5 minutes), which is better placed to be procured and potentially dispatched in quantities commensurate with uncertainty or evolving power system events in the NEM.

Intra-dispatch ramping to address uncertainty and variability

In the NEM, intra-dispatch ramping is "procured" through the dispatch process to meet expected changes in net demand, and through frequency control services to meet unexpected changes in net demand. In particular, unexpected changes in net demand may first be addressed by primary frequency response, and if they are sustained or grow in size (e.g. in the case of forecast ramp uncertainty), then regulation FCAS will be required to ramp up or down to keep the system frequency close to the nominal value of 50 Hz.

Researchers from CEEM have also begun to explore the need for additional intra-dispatch ramping capabilities as utility-scale solar PV capacity approaches approximately 26.7 GW (which corresponds to the installed capacity projected for 2043 under the Neutral case from AEMO's 2018 ISP). Figure 3 presents the ramp rates required to correct the combined variability (e.g. fluctuations around linear dispatch trajectory due to primary energy availability) and uncertainty (e.g. forecast error, which can primarily be attributed to the use of lagged persistence forecasts) of this large capacity of utility-scale solar PV for different moving-average windows. The different moving-average time windows can be thought of as the total ramp response required from frequency control services across different timeframes. For example, shorter moving-average windows (8-32 seconds) correspond to the ramp response required from primary frequency response and potentially faster regulation FCAS (e.g. provision of this service from a battery) to correct power output deviations, whereas a longer moving-average window of 1-minute corresponds to the ramp response required from primary frequency response and more traditional sources of regulation FCAS. The ramp rates calculated from these moving-average windows are compared with the ramp rates of regulation FCAS in 2018 (calculated using Causer Pays data).

The results from this modelling suggest that the need for intra-dispatch ramping due to aggregate utility-scale solar PV variability and uncertainty in the NEM may not be material in the near future. Though a relatively large installed capacity of solar PV was modelled, the results show that the 99th percentile of ramp rate requirements for the 1-minute and 32-second moving-average windows remain under the 99th percentile ramp rate of regulation FCAS in 2018. As expected, to correct the higher resolution variability and uncertainty (16-second and 8-second moving-average windows), the required ramp rate is higher and exceeds the 99th percentile ramp rate of regulation FCAS in 2018. However, it should be noted that we have not modelled the potential ramping contribution of primary frequency response and have not modelled a potentially faster regulation FCAS service that could be delivered by inverter-based resources. Furthermore, this analysis models a relatively large installed capacity of solar PV. As such, these results suggest that intra-dispatch ramping is unlikely to be a material issue in the near future, though further work is required to quantify additional variability and uncertainty from utility-scale wind farms and distributed energy resources.

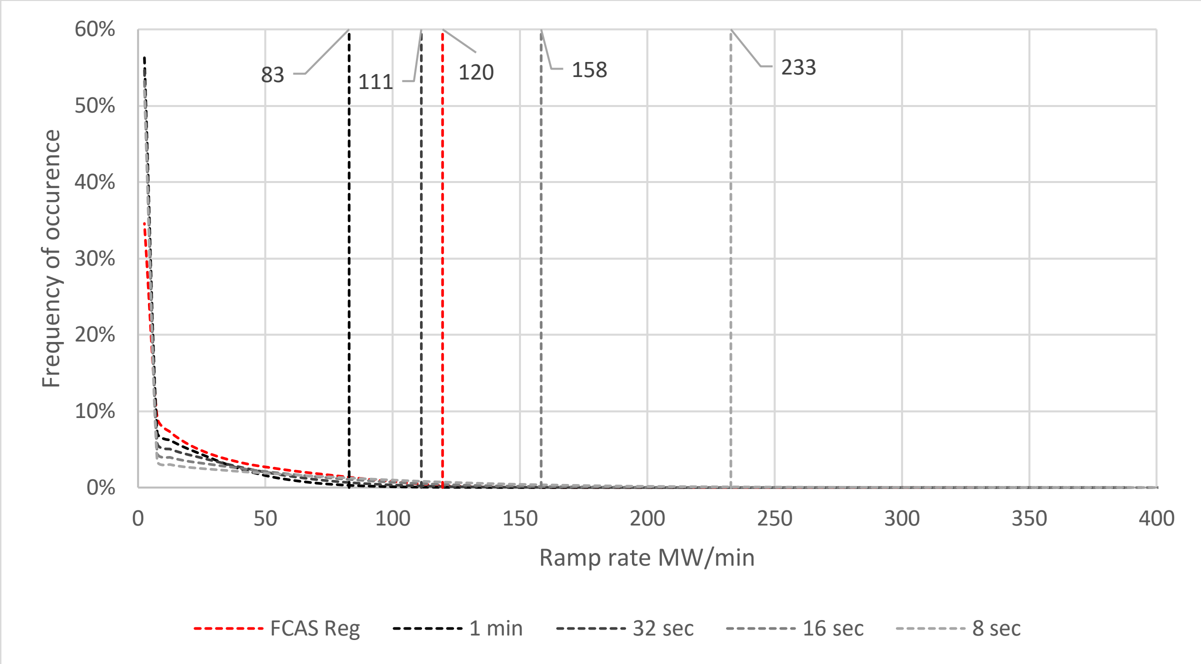


Figure 3: Frequency distributions of aggregated solar PV variability and uncertainty ramp rates with 8-second, 16-second and 32-second moving-average windows of power output for an installed utility-scale solar PV capacity of 26.7 GW. The ramp rates due to solar PV variability and uncertainty have been compared to the ramp rates of regulation FCAS in 2018. For each moving-average window for solar PV variability and uncertainty and for the regulation FCAS ramp rates, the vertical lines show the 99th percentile value (i.e. top 1% ramp rates).

Question from Part B

Q15: What challenges are envisaged in a future with higher variability and uncertainty in net demand?

In our view, the analysis within the ESB's *Options Paper*, the AEMC *Reserve services in the National Electricity Market Directions* Paper and *AEMO's Renewable Integration Study Stage 1 Report* and its associated appendices sufficiently characterise the main challenges over longer timeframes in a future with higher variability and uncertainty in net demand. However, as outlined in our response to Question 26 from Part A of the *Options Paper*, we are of the view that further work can be done to better understand the challenges of higher variability and uncertainty within a dispatch interval. Such analysis would dovetail neatly with a review of key system operating standards and specifications (e.g. the Frequency Operating Standard) and the ongoing reform of the NEM's frequency control arrangements.

Q16: How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?

A reserve service is likely to incentivise commitment and operational decisions regardless of the reserve horizon. In the energy market, unit commitment is self-managed by participants - resources are presumably committed or decommitted in response to expected spot market prices (and, of course, the relative difference between the participant's contract position and the expected spot market price). With this in mind, we anticipate that a relatively short operating reserve horizon (e.g. 5 minutes) effectively acts as an energy price adder as commitment is further incentivised with the potential of capturing expected energy and operating reserve prices. A longer reserve horizon (e.g. 30 minutes) is likely to achieve a similar outcome but through different means. A longer reserve horizon instead enables an operating reserve price to be captured by a participant prior to commitment and provides ample time for a service provider to commit to provide the service, though this commitment is now an obligation.

In our view, the key question here instead is: "how could a reserve service be designed to incentivise operational and investment decisions made by market participants that are beneficial to the system?". While commitment may be beneficial in operational timeframes and could be achieved through either of the reserve horizons, we note that a shorter reserve horizon is a better signal for more flexible resources in investment timeframes as the NEM faces greater variability and uncertainty. In particular, we note that a clear price signal for short-term flexibility may provide a business case to automate demand response and hence unlock latent flexibility in the system[11].

Resources that can respond within short horizons are likely already providing in-market reserves during times of relative scarcity (see our response to Question 26 from Part A of the *Options* Paper). They are also likely to be invaluable in responding to complex power system events if resources that are scheduled to provide energy and/or operating reserves can no longer do so. However, we acknowledge that the relative merits of short reserve horizon need to be better assessed against the potential for fewer providers and less available capacity during the majority of any given day (see *Realisable reserves across reserve horizons*), and the certainty provided to AEMO by a longer reserve horizon.

Q17: Who should pay for reserves and why?

This is a somewhat vexed question as the NEM does not have appropriate and equitable mechanisms for energy users to express a preference for reliability. As discussed in our response to the AEMC's *Reserve Services in the National Electricity Market Directions Paper*, an operating reserve service can enable the demand-side preference for reliability to be better reflected in wholesale market prices[12]. The spot market cap, though relatively high in the NEM, is generally well below the estimated value of customer reliability for both residential and non-residential sectors and across NEM states[13].

However, our view is that an operating reserve service market is not a good substitute for demand side participation and the development of a two-sided market. If an energy user does not wish to pay for a certain level of reliability, a two-sided market could enable that user to express a preference and price for generation/load curtailment. While the incoming wholesale demand response mechanism and the dispatchability model for 'Scheduled Lite' proposed by the ESB for distributed energy resources[14] begin to address this issue, we expect that a consumer who is unaware of or unable to participate in such schemes will shoulder a greater burden of the cost. As such, there could be equity issues if operating costs are allocated to consumers on the basis of additional reliability.

From a system security-oriented perspective, it is also unclear how to allocate costs given that it the 'Causer Pays' principle requires a party that causes the need for the service to be identified. While cost-allocation based on historical resource reliability may incentivise resources to reduce their contribution to power system uncertainty, there is no clear party to assign costs to in the case of forecast uncertainty (particularly if AEMO is responsible for forecasting), transmission failure or cascading failures that are the result of a low probability sequence of events. Much like raise contingency FCAS services, operating reserve costs could be smeared across generators in the NEM, but such costs are likely to be reflected in wholesale prices and thus passed on to consumers.

In our view, the apparent difficult in allocating the costs of operating reserves efficiently warrants extensive consideration and analysis to determine whether such a service is actually needed in the NEM, and if so, when. Failure to do so could result in an increase in costs to consumers and reduce the potential benefits of electricity industry transition.

[11] Energy Synapse, "Demand Response in the National Electricity Market," 2020.

[12] Prakash et al., "Response to Reserve Services in the National Electricity Market Directions Paper," p12.

[13] Australian Energy Regulator, "Value of Customer Reliability Review – December 2019".

[14] Energy Security Board, "Post 2025 Market Design Options – A Paper for Consultation: Part A," p71.

Q19: In what circumstances would a reserve service be beneficial for consumers?

Please refer to our answer to Question 17.

Appendix

Appendix A: Realisable reserves over different reserve horizons

Summary

PLEXOS was used to model the realisable reserve capacities across reserve horizons (i.e. 1 minute to 1 hour) in two NEM regions, New South Wales (NSW) and South Australia (SA), for a year. Both regions were modelled using historic scheduled demand data and AEMO Renewable Integration Study generation mixes for 2020 and scaled scheduled demand and generation mixes based on modifications of the 'Central' and 'Step-Change' scenarios from AEMO's Integrated System Plan scenarios for 2025.

- These regions were chosen as they provide a contrast in generation mix:
    - NSW has a higher scheduled demand and its generation is dominated by coal. NSW also has hydroelectric power stations.
    - In contrast, SA has a lower scheduled demand and no coal or hydro generation. Instead, SA has world-leading penetrations of VRE supplemented by gas plants.
- The 'Central' and 'Step-Change' scenarios were chosen as they "book-end" the most relevant levels of transition in the energy market.
- Regions were modelled as self-contained (i.e. without interconnection). This provides an indication of realisable reserves when reserves cannot be obtained from a neighbouring region (due to interconnector limits), or if regional requirements are applied to an operating reserve service.

Realisable reserve capacities across a year were grouped according to a given time of day (dispatch interval or hour) and a mean (i.e. average realisable reserve capacity for that reserve horizon and time of day) or lower percentile (e.g a percentile of 1% means at this time of day, only 1% of days in the modelled year had a realisable reserve quantity for a particular reserve horizon less than the value reported) were plotted. Note that the modelled operating reserve capacity had a new simulation run for each time horizon. Random number seeds were fixed to maintain the same outage patterns across these runs, but shorter timeframes may show more reserve capacity than longer ones when quantiles are taken. This may be due to a different solution being achieved in a subsequent run – a potential consequence of solver processing time limits.

Key assumptions

Below is a summary of key assumptions used in this model.

I. *Scenario Assumptions*

- 2025 'Central' scenario includes:
    - All "committed" and "maturing" generators (those with at least a confirmed site) dated to be fully operation before the start of 2025 in the AEMO 'NEM Generation Information

January 2021'workbook[15]. For NSW this also included battery projects that are funded for construction in the Emerging Energy Program[16].
    - A load profile based on scaling from 2019 historical scheduled demand to the 2025 'Central' demand trace.
- 2025 'Step-Change' scenario includes:
    - All generators included in the 'Central' scenario plus 50% of publicly announced VRE projects and some select fast-start gas generation dated to be fully operation before the start of 2025 in the 'NEM Generation Information January 2021'workbook. Whilst Snowy 2.0 is not expected to be completed by 2025, we have included it in modelling the 2025 'Step-Change' Scenario for NSW to better account for its potential contribution to operating reserves.
    - A load profile based on scaling from 2019 historical scheduled demand to the 2025 'Step-Change' demand trace.

II. *Generation Assumptions*

- Generation capacity is aggregated in each region by generation type.
- AEMO VRE generation traces are used for wind and PV.
- Demand used is historical scheduled demand obtained from AEMO's NEMWeb through NemSight.
- PLEXOS dispatches batteries on a basis of "daily arbitrage".
- Battery modelled with the same detail as 2020 ESOO model[17].
    - That is, instant start time and 80% charge efficiency.
    - Additional assumption is that proportions of battery max power would be reserved for FCAS and energy arbitrage, with the rest usable for Operating Reserves.
        - 2020 – 30% allowed for operating reserves.
        - 2025 'Central' – 60% allowed for operating reserves.
        - 2025 'Step-Change' – 80% allowed for operating reserves.
- No load/pumping behaviour modelled for pumped hydro.

[15] AEMO, "NEM Generation Information January 2021", 2021. From https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[16] NSW Energy, "Emerging Energy Program", 2020. From https://energy.nsw.gov.au/renewables/clean-energy-initiatives/emerging-energy-program#-further-information

[17] AEMO, "NEM Electricity Statement of Opportunities (ESOO)", 2020. From https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

The table below contains a summary of the modelled properties for each generation technology. Most generation information was based on 2019 and 2020 editions of AEMO's 'Input and Assumptions workbook'[18], with some modifications, and ramp rates were based on the 'GHD, 2018 AEMO cost and technical parameter review databook'[19].

Generation Properties	Coal, CCGT, Gas-Powered Steam	OCGT, Reciprocating Engine	Hydro	Wind, PV	**Generation Properties**	Battery
Units	✓	✓	✓	✓	**Units**	✓
Max Capacity	✓	✓	✓	✓	**Max Power**	✓
Minimum Stable Level	✓				**Capacity**	✓
Heat Rate	✓	✓			**Charge Efficiency**	✓
Max Ramp Up	✓	✓	✓			
Max Ramp Down	✓	✓	✓			
Maintenance Rate	✓	✓	✓			
Forced Outage Rate (Full)	✓	✓	✓			
Outage Factor	✓	✓	✓			
Mean Time to Repair	✓	✓	✓			

The assumed start times used for dispatchable generators are shown in the below table (excluding batteries which were assumed to start instantly)[20].

Generation Type	**Start Time**
Black Coal	2 hours
OCGT	10 minutes (NSW), 5 minutes (SA)
CCGT	30 minutes (NSW), 1.3 hours (SA)
Reciprocating Engine	90 seconds
Gas-Powered Steam Turbine	2 hours
New Fast-Start Gas	2 minutes
Hydro	90 seconds

[18] AEMO, "Input and assumptions workbook", 2019-20. From https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions

[19] GHD, "GHD AEMO revised – 2018-19 Costs_and_Technical_Parameter", 2019. From https://aemo.com.au/en/consultations/current-and-closed-consultations/2019-planning-and-forecasting-consultation

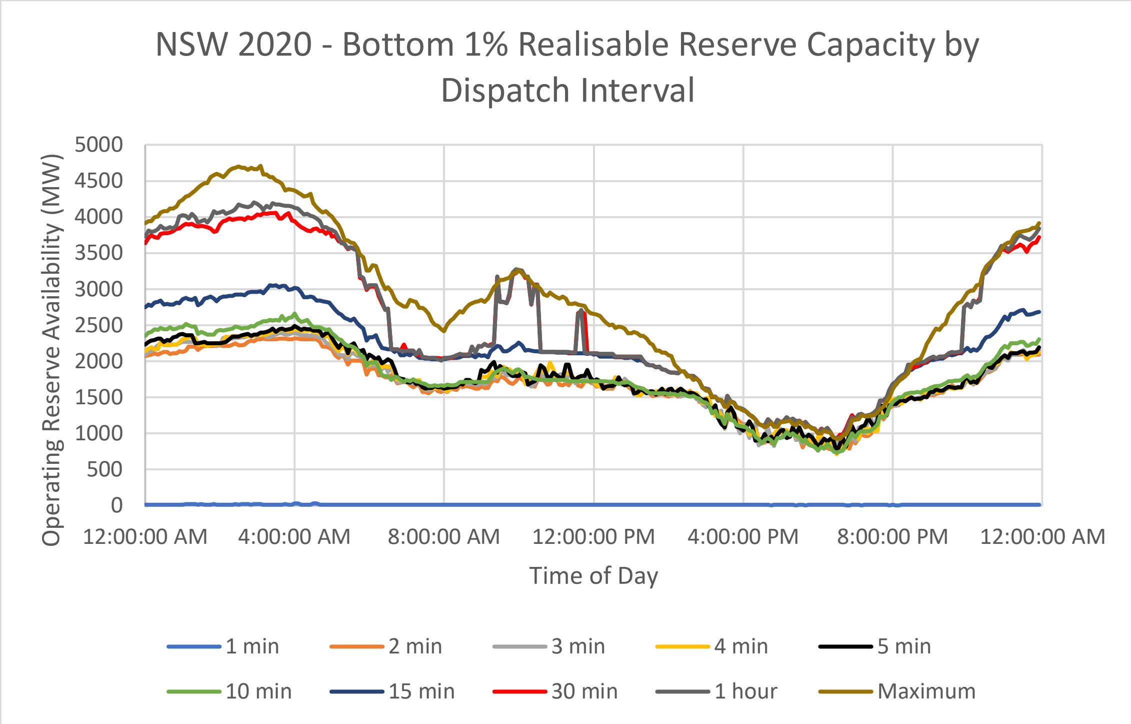
[20] Aurecon, "Generator Technical and Cost Parameters", 2020. From https://www.electranet.com.au/wp-content/uploads/projects/2016/11/508986-REP-ElectraNet-Generator-Technical-And-Cost-Parameters-23July2020.pdf; Aurecon, "2020 Cost and Technical Parameter Review", 2020. From https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/aurecon-cost-and-technical-parameters-review-2020.pdf?la=en; Clean Energy Council, "Hydroelectricity Fact Sheet", 2012. From https://www.awa.asn.au/Documents/Hydro-Fact-Sheet-An-Overview-of-Hydroelectricity-in-Australia.pdf; Parsons Brinckerhoff, "Technical Assessment of the Operation of Coal & Gas Fired Plants", 2014; SDA Engineering, "Angaston Power Station", 2018. From https://www.sdaengineering.com.au/portfolio_page/fairfax-printers-backup-power/

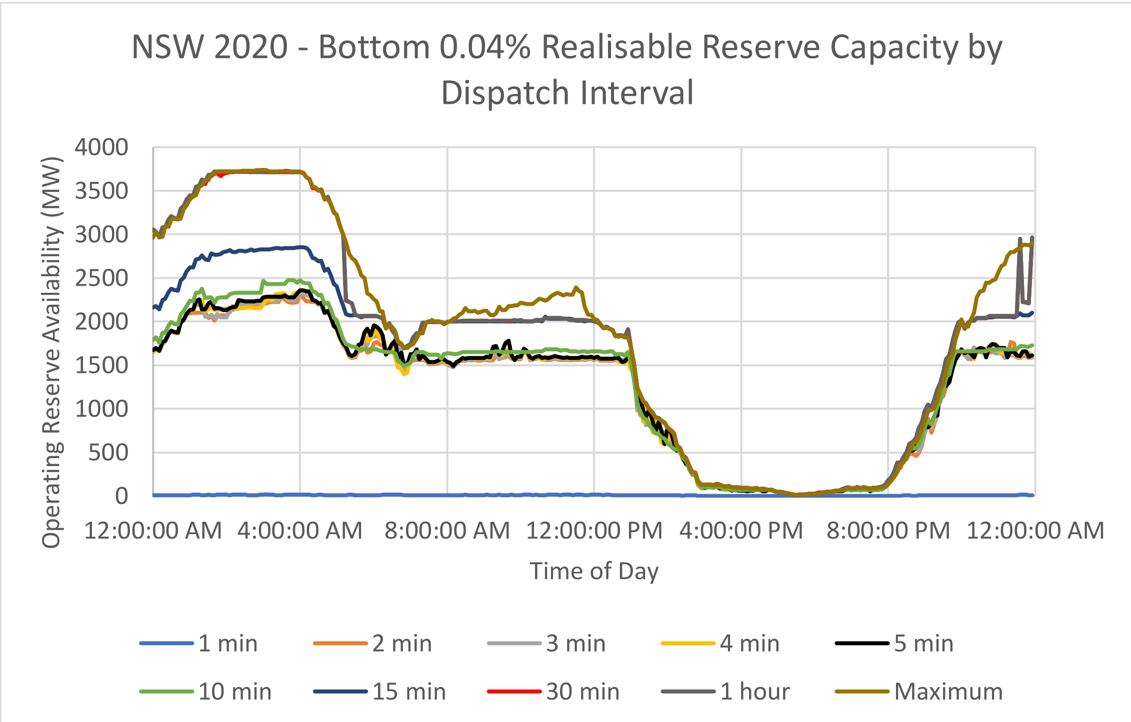
PLEXOS models economic dispatch with perfect foresight. To do this, PLEXOS requires offers for energy at for price-quantity pairs. Four price-quantity pairs were determined to be sufficient to model expected market outcomes with validation through comparison of modelled and historical capacity factors and through a comparison of modelled and historical generation mixes. The offers used by each generation type are outlined in the table below.

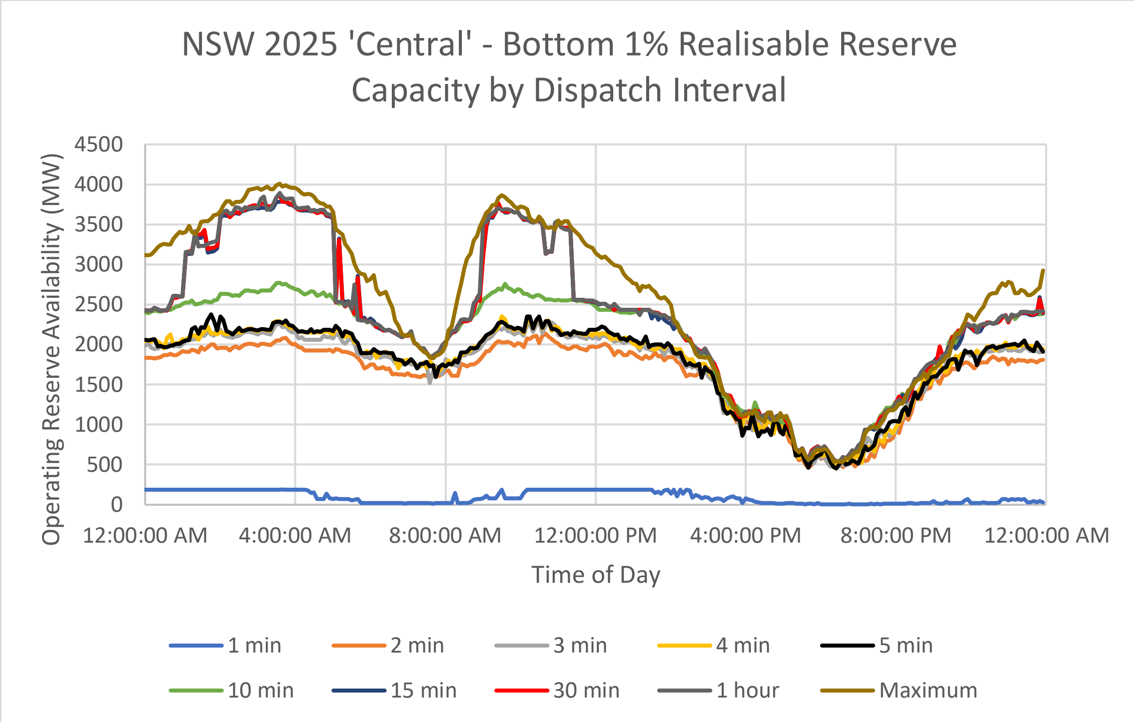
	Indicative Offer Prices ($/MWh)			
Generator Type	**Band 1**	**Band 2**	**Band 3**	**Band 4**
Coal	Floor	SRMC	SRMC+20	Ceiling
CCGT	Floor or Low	SRMC	SRMC+100	-
OCGT	SRMC	SRMC+100	SRMC+300	Ceiling
Reciprocating Engines	SRMC	SRMC+100	SRMC+300	Ceiling
Gas-Powered Steam	Floor	SRMC	Ceiling	-
Hydro	Low	Medium	High	Ceiling
Wind	Floor	-	-	-
PV	Floor	-	-	-

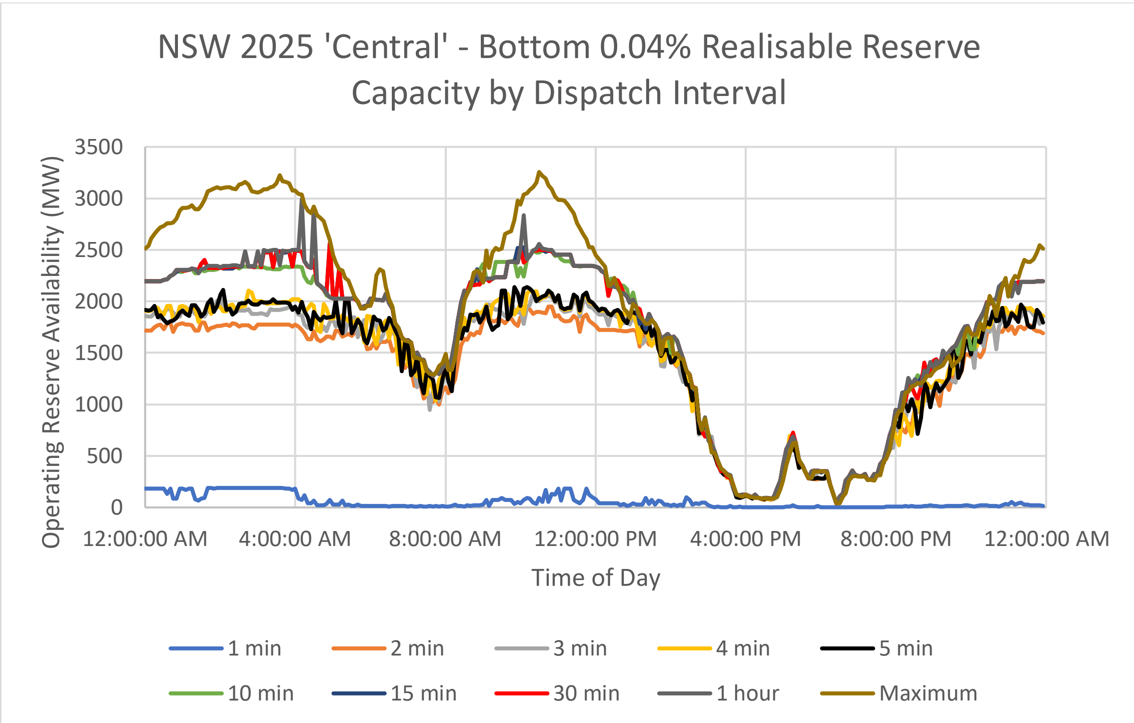
Region	**Generation Type**	**Modelled Capacity Factor (%)**	**Historical Capacity Factor (%)**	**Difference (Model-Historical) (%)**
NSW 2020	Black Coal	65.10	60.11	+ 4.99
	OCGT	1.82	1.62	+ 0.20
	CCGT	24.11	22.62	+ 1.49
	Hydro	11.3	9.03	+ 2.27
	PV	28.68	28.43	+ 0.25
	Wind	34.40	34.65	- 0.25
SA 2020	OCGT	2.28	3.23	- 0.95
	CCGT	49.02	55.66	- 6.64
	Reciprocating Engine	9.23	13.39	- 4.16
	Gas-Powered Steam Turbine	14.86	17.5	- 2 .64
	PV	26.80	24.66	+ 2.14
	Wind	34.53	34.23	+ 0.30

Appendix B: 1% and 0.04% Lowest Realisable Reserve Capacity for NSW and SA in 2020 and 2025






NSW 2025 'Central' - Bottom 1% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
4500
4000
3500
3000
2500
2000
1500
1000
500
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


NSW 2025 'Central' - Bottom 0.04% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
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3000
2500
2000
1500
1000
500
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
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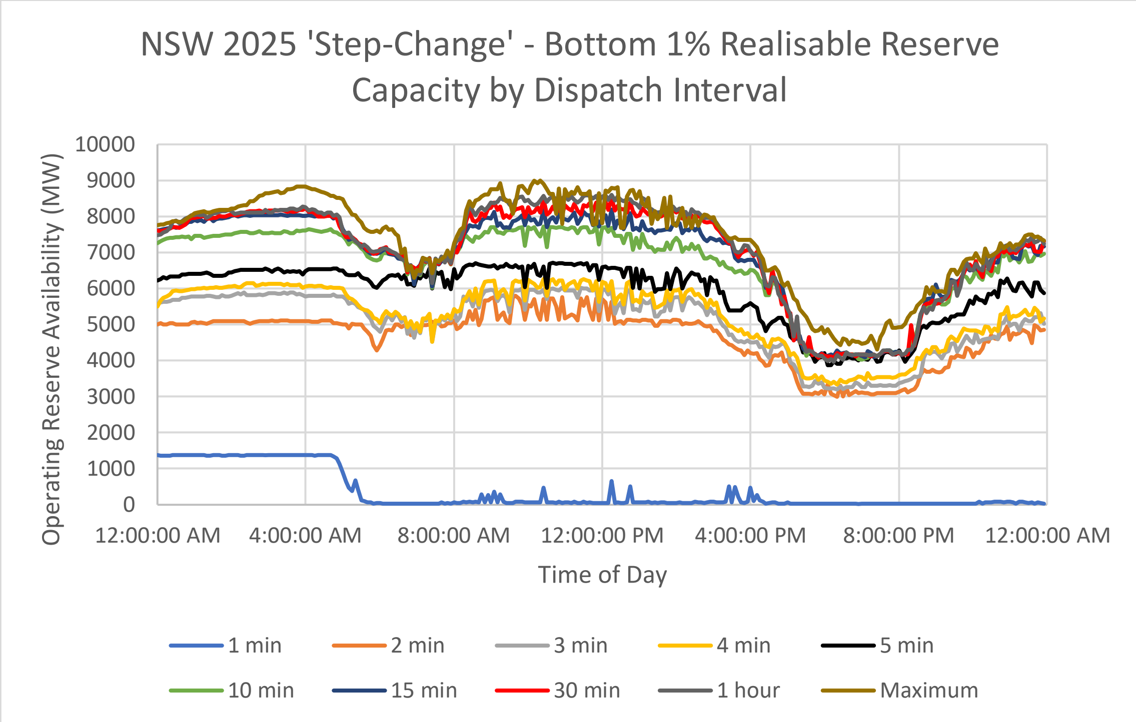
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


NSW 2025 'Step-Change' - Bottom 1% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
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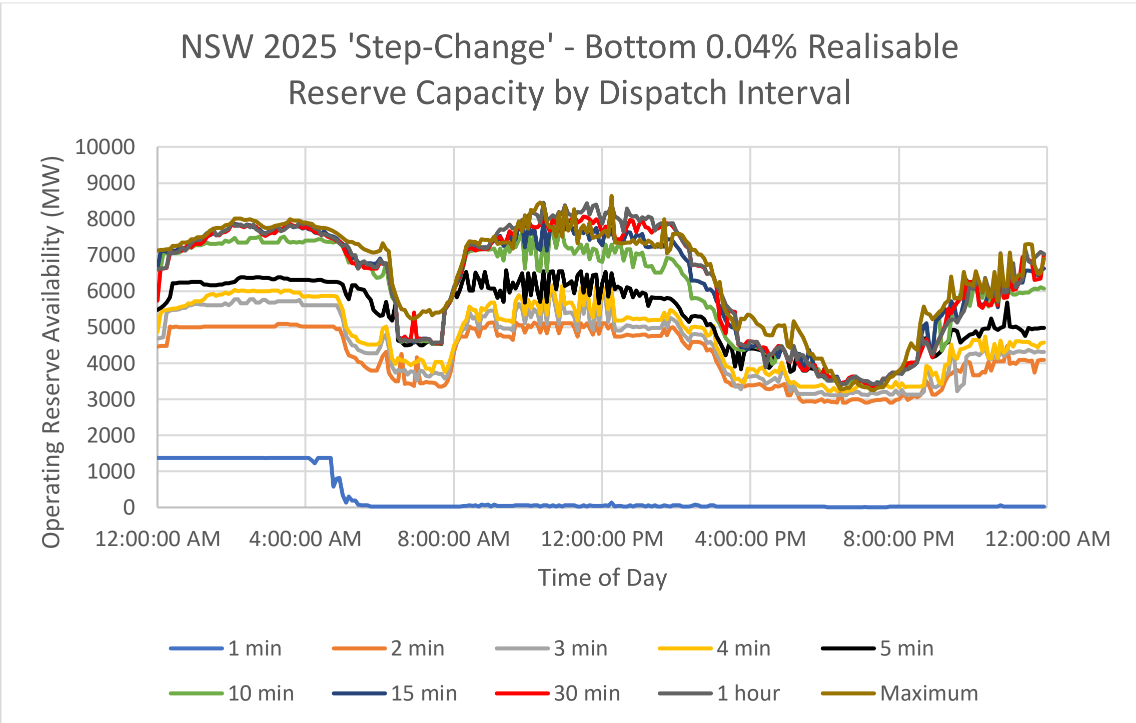
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


NSW 2025 'Step-Change' - Bottom 0.04% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
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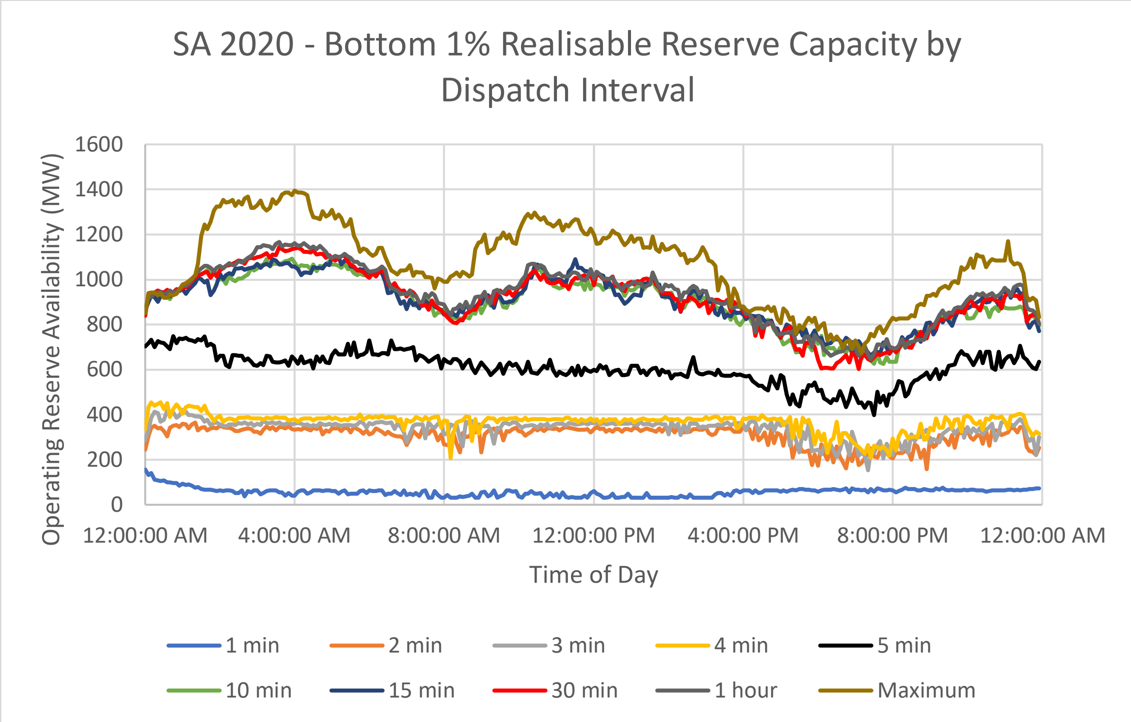
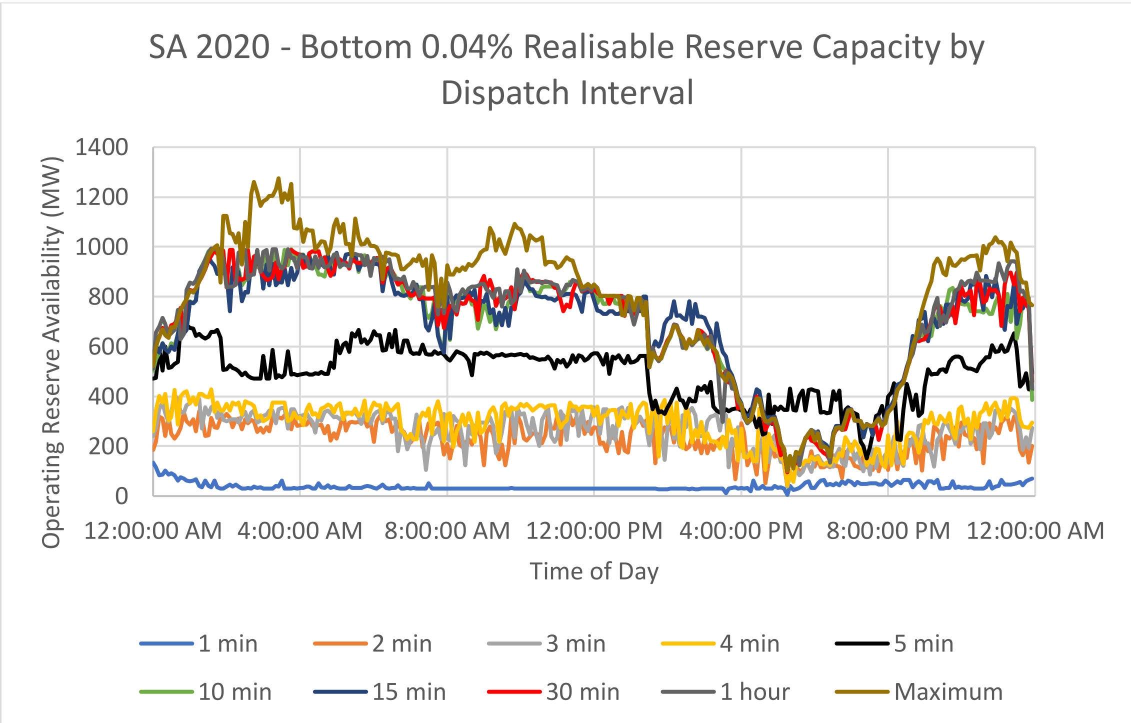
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2020 - Bottom 1% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
1600
1400
1200
1000
800
600
400
200
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2020 - Bottom 0.04% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
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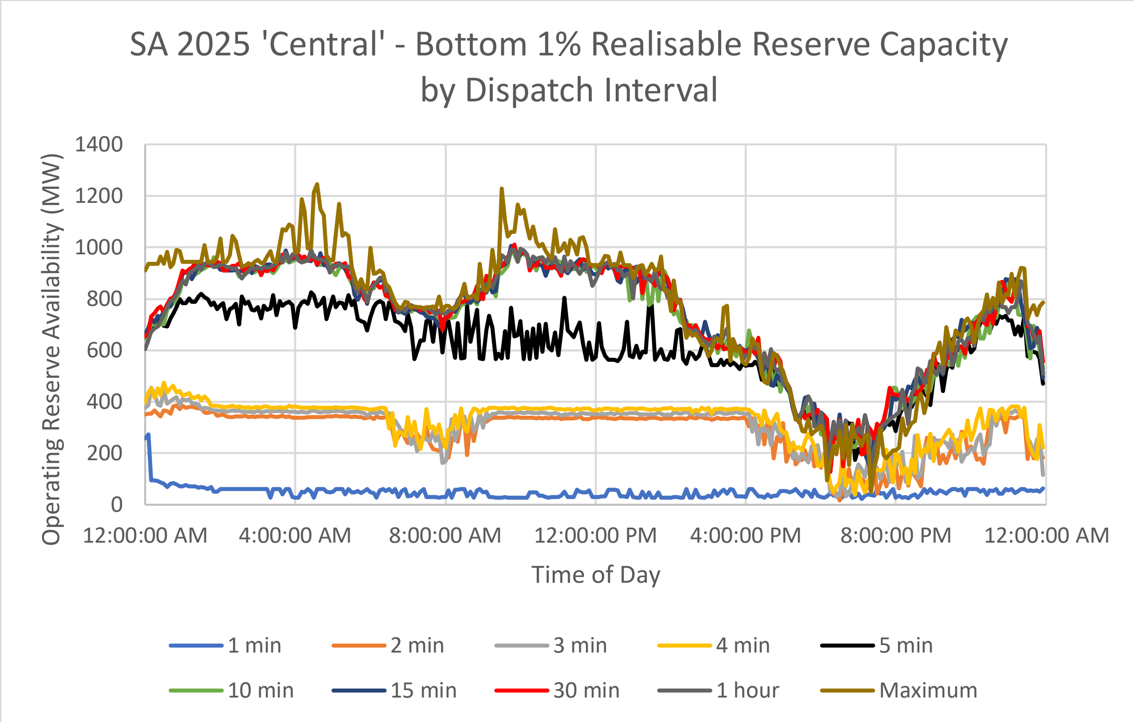
1200
1000
800
600
400
200
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2025 'Central' - Bottom 1% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
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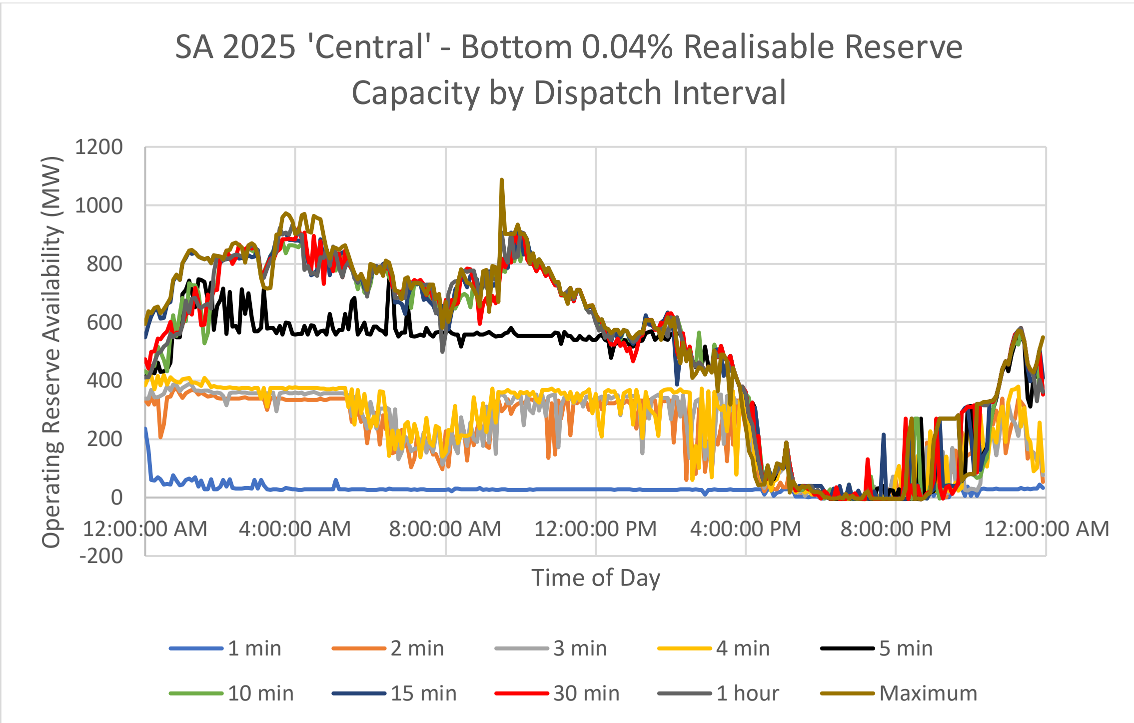
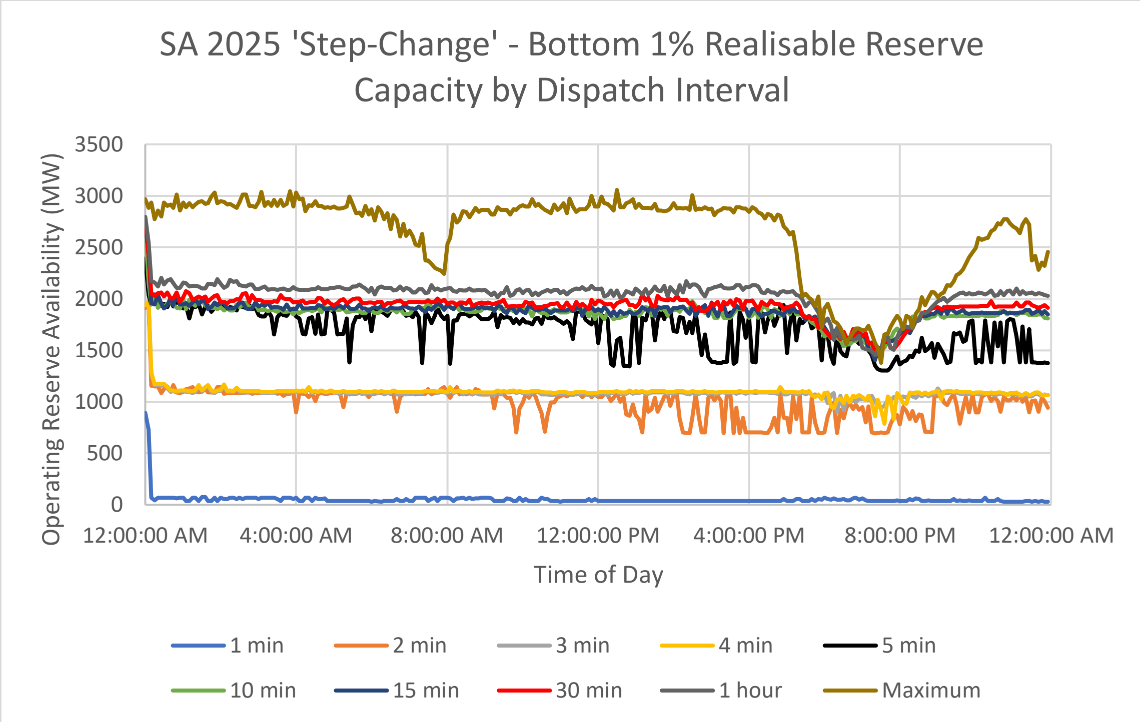
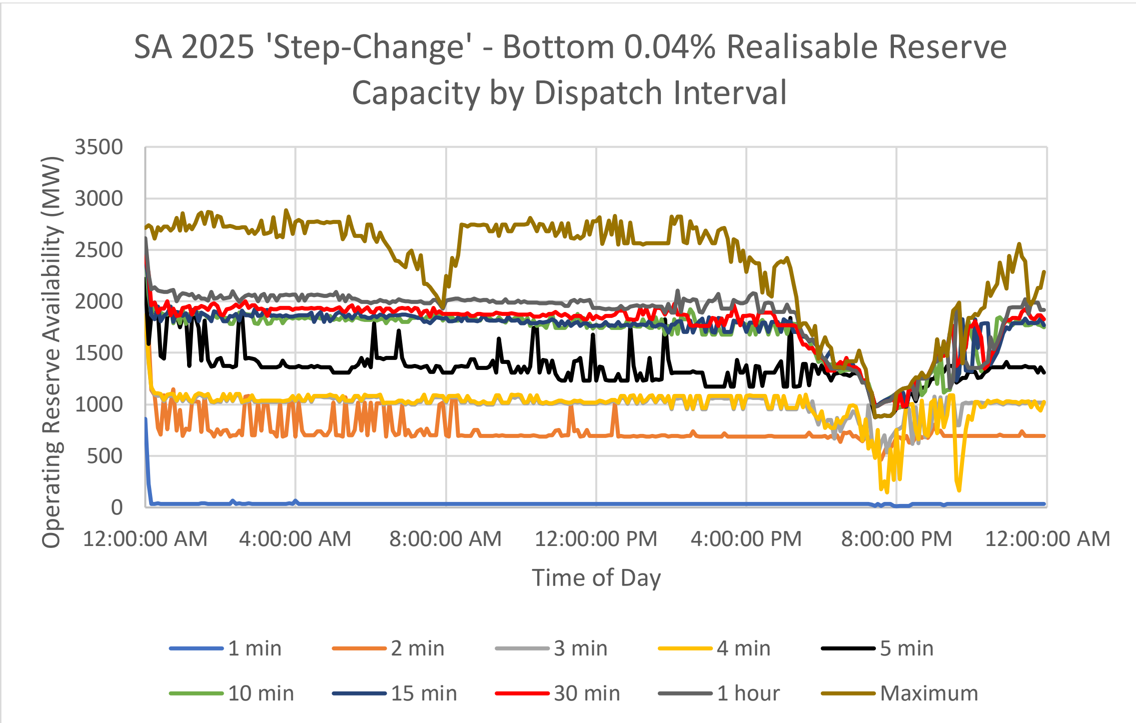
1200
1000
800
600
400
200
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2025 'Central' - Bottom 0.04% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
1200
1000
800
600
400
200
0
-200
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2025 'Step-Change' - Bottom 1% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
3500
3000
2500
2000
1500
1000
500
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum


SA 2025 'Step-Change' - Bottom 0.04% Realisable Reserve Capacity by Dispatch Interval
Operating Reserve Availability (MW)
3500
3000
2500
2000
1500
1000
500
0
12:00:00 AM
4:00:00 AM
8:00:00 AM
12:00:00 PM
4:00:00 PM
8:00:00 PM
12:00:00 AM
Time of Day
1 min
2 min
3 min
4 min
5 min
10 min
15 min
30 min
1 hour
Maximum

Appendix C: Intra-dispatch ramping required to address variability and uncertainty of high penetrations of solar PV

Method & Assumptions:

Generation from solar PV in the NEM was aggregated across Renewable Energy Zones defined in ISP 2018[21] using a published method that generates 4-second synthetic PV generation timeseries of individual solar farms from Causer Pays data [22]. To model a high PV penetration scenario, the installed capacity of 26.7 GW at the last year of the 2018 ISP Neutral Case projection (i.e. 2043) was used. This 4-second aggregated PV generation timeseries is then used to analyse aggregate PV variability.

Frequency controls services are used to correct frequency deviations that may occur due to the generator's actual power generation deviating from its dispatch target. For semi-scheduled generators, this includes both variability due to the nature of the primary energy resources and forecast uncertainty. Hence, the frequency control service requirement that arises from PV generation can be defined as:

Eq.1
$$FCS\ (t) = P_{t_{MA}}\ (t) - P_{forecast}(t)$$

Where $FCS\ (t)$ is the frequency control service requirement at time t, $P_{t_{MA}}\ (t)$ is the smoothed power output calculated by moving average over a time window of t_{MA} (Eq. 2).

Eq.2
$$P_{t_{MA}}\ (t) = \frac{1}{N}\sum_{t=t-{t_{MA}}/_2}^{t=t+{t_{MA}}/_2} P_{4\,sec}(t)$$

A smoothed profile with a variable moving-average window is used instead of the 4-second power output to investigate ramping requirements that are associated with various frequency control services. For example, a 1-minute moving average accounts for the delay in AGC response that generally exist in the system, whereas a shorter window would begin to incorporate response requirements for primary frequency control.

$P_{forecast}(t)$ is the forecast power output. It is calculated by using a 5-minute shifted 10-minute moving average of the solar farm's power output. This has been done to replicate the linear trajectory of a 5-minute dispatch target and the 5-minute lag associated with ASEFS' persistence forecast[23].

The ramp rate requirement for frequency control services can then be calculated using Eq. 3.

Eq.3
$$FCS\ ramp\ rate\ (t) = FCS\ (t) - FCS\ (t-1)$$

[21] AEMO, "Integrated System Plan For the National Electricity Market" (Australian Energy Market Operator, 2018).

[22] Kanyawee Keeratimahat et al., "Generation of Synthetic 4 s Utility-Scale PV Output Time Series from Hourly Solar Irradiance Data," *Journal of Renewable and Sustainable Energy* 13, no. 2 (March 2021): 026301, https://doi.org/10.1063/5.0033855.

[23] Australian Energy Market Operator, "Scheduling Error Report: AWEFS and ASEFS Unconstrained Intermittent Generation Forecast (UIGF) Scheduling Errors - 2012 to 2016," 2016.

Acknowledgements

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The views presented in this submission are solely those of the authors, and don’t necessarily represent the views of the Digital Grid Futures Institute or, more generally, UNSW Sydney.