Renewable Integration Study Stage 1 Appendix C: Managing variability and uncertainty

April 2020

Important notice

PURPOSE

This is Appendix C to the Renewable Integration Study Stage 1 report, available at https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

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C1. Appendix C summary

C1.1 Increasing variability and uncertainty in the NEM

The magnitude and frequency of large ramps in variable renewable energy (VRE) across the NEM is increasing. This means there will be larger and more frequent fluctuations in generation that will need to be managed to maintain the supply-demand balance.

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. This increased variability and uncertainty changes the behaviour of the system, and the operators need new controls to keep it operating reliably and securely.

To understand the impact of increasing wind and solar penetrations on the system's ability to meet future ramping requirements, several analyses were undertaken to characterise projected levels of variability and uncertainty in the NEM and the current tools available to manage system flexibility under various levels of uncertainty.

C1.2 Flexibility and risk management

Power system flexibility encompasses fleet (generation and load), network, and behavioural components. Enhancements to flexibility can me met through more flexible generation, stronger transmission and distribution networks, more storage, more flexible demand, enhancements to regulatory frameworks and participant learning, and operational experience under new market and physical conditions.

To effectively integrate higher levels of VRE, while maintaining a secure and reliable grid, flexibility needs to be harnessed in all parts of the power system.

Analysis in this paper focuses on the ability of the system to act flexibly, to fully utilise the VRE that is built out to 2025, under the Draft 2020 ISP Central generation build. However, it is also acknowledged that as the system moves to higher penetrations of VRE, there is likely to be a level of VRE curtailment that is determined by the market to manage variability and uncertainty, as it relates to participant risk and risks to system security.

Market participants operate their portfolios to manage risk and will endeavour to cover their exposure to pricing and operational impacts from variable and uncertain conditions. However, as a system operator, **it is incumbent on AEMO to maintain power system security, and as such monitor and manage any security risks to the system**. To assess the ramping requirements and capability of the system to respond across different timeframes, new operational tools and processes will be required. Appropriate regulatory frameworks should also be considered to ensure market signals align with this system need.

C1.3 Summary of actions

The following actions are made or supported by this report. A detailed discussion of these actions is available in Section C6.

Table 1 Summary of challenges and proposed actions

Challenge	Proposed action	Reference to this appendix	Reference to main report
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.	AEMO to redevelop existing scheduling systems (Pre-Dispatch [PD] and Short Term [ST] PASA) to better account for system needs, including: • Availability of essential system services, including inertia, system strength, and ramping requirements. • Catering for cross-regional sharing of reserves. • Better modelling of new technologies, including variable renewable energy (VRE), batteries, and distributed energy resources (DER – including demand response and virtual power plants [VPPs]).	• **Section C2.3.3:** Overview of current reserve assessment (PASA) systems and uncertainty. • **Section C3:** Describes the increase in VRE in the system, necessitating better modelling of these technologies (and associated ramping requirements) in operational tools. • **Section C5:** Assessment of system flexibility to meet ramping requirements and highlights the need for operational tools to identify system ramping requirements in operational timeframes to ensure the right mix of resources is available.	**Action 2.2**
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.	AEMO to improve understanding of system uncertainty and risk, particularly during ramping events, by exploring: • Trialling and implementing a ramping forecast and classification prototype. • Deployment of additional weather observation infrastructure that is fit for purpose for the energy industry.	• **Section C4**: Assesses the ability of current forecasting tools to predict variability and potential areas for enhancements.	**Action 6.1**
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.	As part of its post-2025 market design program, the ESB is assessing market mechanisms that increase certainty around system dispatch of energy and essential system services (inertia, system strength, minimum synchronous units, operating reserves, and flexibility) as real time approaches. The ESB will recommend a high-level design to the COAG Energy Council by end of 2020 for implementation by 2025.	• **Section C3 and C4**: Assesses the increased variability and uncertainty in the system that will need to be managed. • **Section C5**: Assesses the ability of the system to provide flexibility to meet ramping requirements, under current market frameworks.	**Action 2.3**
	Improve the reliability of information provided by the VRE fleet to support security constrained dispatch. The ESB is coordinating several interim measures to improve the visibility of and confidence in resources in the NEM, to ensure security can be maintained while new market arrangements are developed	• **Section C2.3:** Identifies current treatment of semi-scheduled generators. • **Section C5:** Assessment of system flexibility and the importance of being able to schedule the right resources at the right times to manage ramping requirements.	**Action 6.2**

C2. Introduction

C2.1 Scope and structure of this Appendix

This Appendix to AEMO's *Renewable Integration Study Stage 1* report[1] provides additional technical detail related to the overview information in Chapter 6 of the report.

The structure of the Appendix is as follows:

- **Section C3** details the level of VRE and net demand **variability** in the NEM, by analysing the magnitude and frequency of ramping across different timescales and spatial aggregates. This includes an analysis of historical operational data as well as simulated 2025 data, to understand trends in variability over time.
- **Section C4** provides insight on wind and solar generation **uncertainty** for extreme ramping[2] events, using historical operational data and historical forecast data.
- **Section C5** assesses the technical implications arising from the discussion in sections C3 and C4, and whether the system (including the physical fleet) is equipped to manage the increased risk to the grid.
- **Section C6** provides an overview of recommended actions and future work for managing future variability and uncertainty.
- **Section C7** includes supplementary materials for this appendix. Information is provided on:
  - Data, approach and assumptions used for the analysis.
  - Statistical concepts.
  - Additional graphs and tables.

This appendix focuses on ramping of VRE and **net demand[3]** across the NEM. It provides analysis of VRE components (wind, utility solar, and distributed solar PV [DPV]), individually and as contributors to movements in net demand. Case studies and analysis on a regional level are provided intermittently throughout this appendix.

C2.2 Objectives of this study

This report is a subset of AEMO's Renewable Integration Study (RIS), focusing on the variability and uncertainty associated with wind and solar technologies and their impact on system operations.

The aim of this study is to **form a view on the challenges associated with operating the NEM with an increasing penetration of utility wind, utility solar, and DPV**.

These challenges have been assessed through analysis of a historical study period between January 2015 and April 2019 against a projected 2025 year, which uses VRE penetration and demand information from the Draft 2020 ISP Central scenario[4].

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[1] At https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

[2] Ramping is the megawatt change in generation output between the start and the end of an interval (for example, a 5-minute interval or a 1-hour interval).

[3] In this report, net demand means underlying demand net of VRE generation, that is, demand that must be met by scheduled generation sources and not by wind or solar (including utility solar and distributed solar PV resources). See Section C3.4 for details.

[4] See AEMO, Draft 2020 ISP, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan.

Understanding the magnitude of these challenges and associated level of risk will determine the requirement for enhancements to system flexibility and advances in forecast modelling, operational tools, and market mechanisms.

The key objectives are to:

- Quantify variability in the NEM, through an analysis of ramps across VRE and net demand concepts, to understand how these are changing over time and the added risk to system operation.
- Assess historical ramp uncertainty in supply forecasts and form a view on how uncertainty may be managed operationally as the penetration of VRE increases.
- Consider the technical implications of more variable and uncertain system conditions, including the requirements on fleet flexibility, and implications for rate of power flow and voltage control.
- Consider the possible avenues for managing the increased risk to system operation. The solutions considered build on those in the *AEMO observations: Operational and market challenges to reliability and security in the NEM* report[5].

C2.3 Background

C2.3.1 Growth in variable renewable resources

There is a global trend in electricity generation, shifting from fossil fuels towards VRE resources including wind, utility (grid-connected) solar, and DPV[6]. In the NEM, the installed capacity[7] of VRE has grown significantly over the last decade, and this trend is expected to continue.

As Figure 1 shows, there was modest growth in VRE installed capacity in the NEM between 2007 and 2014 of 0.9 GW/year, then the rate of installation between 2015 and 2019 increased threefold to 2.7 GW/year. Based on the 2020 ISP Central scenario, an additional 8.4 GW of VRE is projected to be installed in the NEM between 2019 and 2025.

For the power system to operate securely and reliably, **energy supply and demand must always be balanced**. To balance supply and demand, AEMO runs a centrally coordinated, security-constrained economic dispatch process in real time. In this process, AEMO issues dispatch targets to all scheduled and semi-scheduled generating units to meet total demand[8,9]. Currently in the NEM, semi-scheduled generators are exclusively wind and solar resources.

A semi-scheduled unit is characterised as a generating system with intermittent output and typically has an aggregate nameplate capacity of 30 MW or more[10]. Their available output at any point in time depends on the available wind and solar input, which are highly variable from one dispatch interval to the next. AEMO can limit a semi-scheduled generator's output for a variety of reasons, most commonly in response to network constraints for security purposes or if the unit is not economically cleared (that is, output has been priced at

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[5] At https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.pdf.

[6] In this report, DPV systems are considered to be residential distributed solar PV and PV non-scheduled generation (PVNSG, commercial-scale) that is behind the meter and < 30 MW.

[7] Installed capacity in this report refers to the generating capacity (in MW) of the following (for example): a single generating unit; a number of generating units of a particular type or in a particular area; or all of the generating units in a region. DPV installed capacity is the total amount of cumulative DPV capacity installed at any given time.

[8] For information on AEMOs dispatch process, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705---Dispatch.pdf.

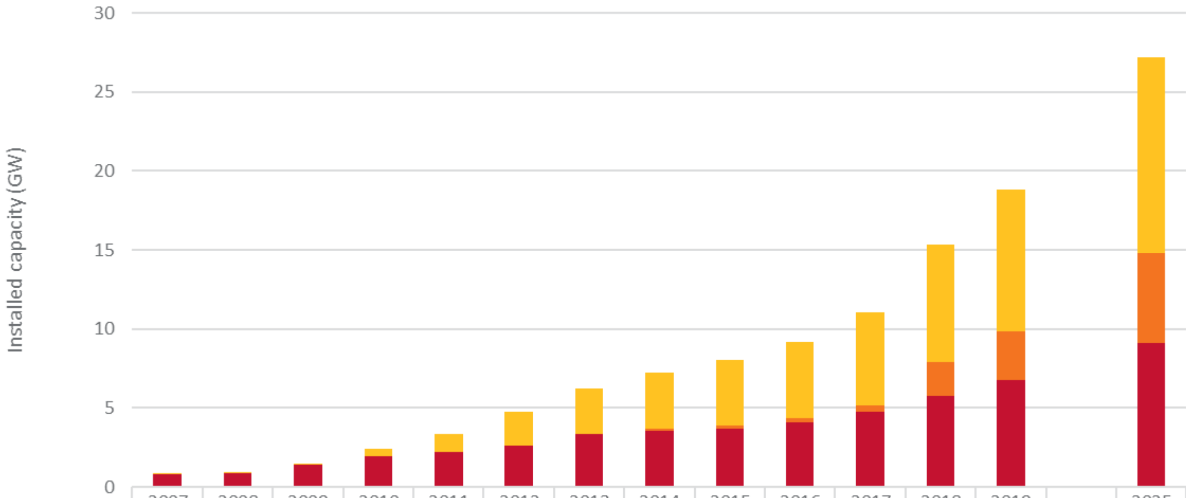
[9] Total demand is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generator and interconnector imports, excluding the demand of local scheduled loads and the allocated interconnector losses. Definitions and information on AEMOs demand terms are at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

[10] There are some generating units in the NEM with a nameplate rating of < 30 MW that are also classified by AEMO as semi-scheduled generating units under National Electricity Rules (NER) clause 2.2.3(c).

an above-market clearing price), but at other times the generator can supply any amount up to its maximum registered capacity.

As semi-scheduled generating units (wind and solar) can produce any output the majority of the time[11], it is useful to introduce the concept of **net demand**, which is the demand that must be met by scheduled generation sources only and not by wind or solar (including semi-scheduled and non-scheduled generators and DPV) resources. That is, net demand is the sum of underlying demand from electrical loads and any variations in wind and solar output.

Figure 1 NEM installed VRE capacity by fuel type, 2007-19 and forecast to 2025



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		2025
DPV	0.00	0.02	0.09	0.44	1.19	2.13	2.85	3.57	4.19	4.84	5.88	7.45	9.00		12.39
Utility Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.18	0.26	0.41	2.16	3.05		5.67
Wind	0.79	0.89	1.41	1.98	2.19	2.63	3.37	3.58	3.69	4.07	4.77	5.76	6.77		9.13

C2.3.2 Impact of variability and uncertainty on power system operation

Fluctuations in energy supply and demand – so-called “**ramps**” – create challenges for maintaining balance in the system.

> A **ramp** is an upward or downward fluctuation in supply or demand over a defined time interval. For example, a **solar ramp** may be caused by cloud movement, and a **demand ramp** by changing customer needs over the day.

Variability and uncertainty are inherent in all power systems, even without the presence of wind and solar. Historically, fluctuations in the system were mainly due to movement in underlying demand[12] and generation and transmission availability (including forced outages).

The dispatch process[13] in the NEM was designed to manage traditional forms of variability (such as intra-day and seasonal changes in demand) and uncertainty (such as forced outages). These forms of variability are largely predictable, and conventional generation can be scheduled to meet these expected changes. Excess supply is also available in the system to guard against unexpected credible contingency events (such as the loss of a generating unit) or variances from the demand forecast.

As more VRE is integrated into the grid, more variability and uncertainty are introduced, which changes the behaviour of the system. The rapid increase in deployment of wind and solar, and the resultant output

[11] Subject to dispatch instructions in the NEM Dispatch Engine (NEMDE), as detailed on the previous page.

[12] Underlying demand in this report means all electricity demand that is met by local scheduled, semi-scheduled, non-scheduled generation, and DPV generation, and by interconnector imports to the region.

[13] The dispatch process means the process detailed by the Power System Operation Procedure SO_OP_3705, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705---Dispatch.pdf.

fluctuations on a minute-to minute basis and increasing reliance on weather forecasts (which can never be perfect), has made variability and uncertainty a focal point for AEMO.

This increase in uncertainty and variability is occurring on both the supply side (due to increased utility wind and solar generation) and the demand side (due to the increased uptake of DPV).

The report explores the **system flexibility requirements** to cover different levels of variability and uncertainty.

C2.3.3 How variability and uncertainty is managed in the NEM

Market participant portfolio management

Risk management is a core business component of industry participants operating in the energy market. While market participants must buy and sell electricity through the spot pool operated by AEMO, they are free to structure alternate hedging and risk management arrangements outside of this pool. Without hedging, a market participant would be exposed to price uncertainty and volatility.

There are several hedging options available to market participants, including exchange-traded contracts (such as those traded via the Australian Stock Exchange [ASX]), over the counter (OTC) contracts, power purchasing agreements (PPAs), or self-hedging through vertical integration across wholesale and retail operations in the NEM (known as gentailing).

Market participants who have hedged their spot market position no longer have their electricity revenue or costs entirely exposed to the volatile spot prices. Instead, these revenue or cost streams now depend on a combination of the hedged energy contract prices and the unhedged energy exposed to the spot price. As a result, there is a wide range of different participant-specific bidding behaviours across the NEM, depending on their exposure in the spot market on the day, which is itself influenced by a range of factors including demand conditions, plant status, and contract position.

As the energy market transforms and new operational and market conditions emerge, there is the opportunity for innovation in hedging markets in response to the risks associated with a high VRE system (for example firming products). However, there are also interim challenges that may disrupt participant risk management. For example, if there is a high degree of market intervention during the transition to a higher VRE system[14], this will increase the likelihood of interference with participants' management of their asset portfolios and operations (including fuel management and maintenance schedules).

Frequency control ancillary services markets

In real time, during conditions where supply and demand are not balanced, the frequency of the system will deviate. To the extent possible, enabled frequency control ancillary services (FCAS) providers (regulation, and contingency if the local frequency deviates far enough) will cover this change in the supply demand balance.

Mismatches are managed by a combination of regulation frequency control through the automatic generation control (AGC) system and primary frequency control (PFC), which is provided voluntarily within the normal operating frequency band (NOFB) and procured through contingency FCAS markets outside the NOFB.

Further discussion on frequency control can be found in Appendix B, and further work has been commissioned on frequency control within the NOFB, to supplement this work.

[14] Market intervention may be necessary to ensure that the system operates within its technical envelope at all times. For more information, see discussion on reserve assessment and intervention, below, or Chapter 2 of the RIS Stage 1 report for a discussion on system operability, including interventions, during the energy transition.

Reserve assessment and intervention

AEMO conducts reserve assessments ahead of real time[15] to ensure there is enough supply to meet demand. These are the Projected Assessment of System Adequacy (PASA) processes. A Lack of Reserve (LOR) is declared when these assessments project a probability of capacity reserves being insufficient to avoid load shedding[16], given reasonably foreseeable conditions and events[17].

LOR declarations have the following objectives:

- Provide information to market participants on the expected level of short-term capacity reserve. Market participants can then respond to this information by voluntarily committing more capacity to the market.
- The LOR 2 level provides a benchmark for AEMO to intervene in the market to commit extra capacity.

Uncertainty is accounted for in AEMO's reserve assessment through incorporation of the **Forecast Uncertainty Measure** (FUM). The following variable components are considered by the FUM:

- Temperature forecast.
- Solar irradiance forecast.
- Forecast output of semi-scheduled (wind and solar) generating units.
- Current demand forecast error for forecast lead times below 24 hours.
- Current supply mix by fuel type (coal, gas or hydro).

Use of a risk-based measure in reserve calculations provide a more accurate assessment of required reserves needed to manage uncertainty and maintain the reliability.

The objective of reserve assessment (the PASA process) is to maximise the reserve that is available to the whole system. However, while reserves may be available, no assessment is made of their ability to respond to a change in the supply-demand balance in the timescale required. That is, there is no guarantee of system **flexibility** to ensure the supply-demand balance, even if reserves exceed demand.

Further, the signal provided to market participants by the reserve assessment processes is on an information-only basis, with no guaranteed corresponding price signal to value to the provision of reserves.

If the voluntary market response is insufficient to address the supply or reserve shortfall, AEMO will intervene by exercising **Reliability and Emergency Reserve Trader (RERT)** or, where necessary, **issuing directions**. Directions in these conditions include, for example, reducing the largest credible risk (to reduce the requirement for reserve) and directing plant online to increase the availability of supply.

In cases where actual supply plus available reserve is no longer adequate – that is, there is insufficient online generation, offline generation which can start up in the required timeframe, and intra and inter-regional transfer capability available to balance supply and demand securely – AEMO may be required to instruct **manual load shedding**. Load shedding will occur as a last resort when there are no other options available to AEMO. If supply scarcity is not well forecast, then there will be less time available to intervene in the market, making load shedding a more likely outcome.

VRE curtailment

VRE may be curtailed for a number of reasons. For example, AEMO's 2019 Q4 *Quarterly Energy Dynamics* report[18] highlighted that contributors to VRE curtailment over the reporting period included:

[15] Every day, AEMO publishes the Pre Dispatch Projected Assessment of System Adequacy (PD PASA) for the following day, and the Short Term (ST) PASA looking two to seven days ahead. The LOR assessment horizon is from the current time to the end of the period covered by the most recently published ST PASA.

[16] Other than interruptible load.

[17] See the reserve level declaration guidelines at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf.

[18] See https://aemo.com.au/-/media/files/major-publications/qed/2019/qed-q4-2019.pdf?la=en&hash=A46E0A510AE9F127B0A991B312C54460.

- Participants managing their own risk through self-curtailment in response to market signals, such as negative prices.
- AEMO managing risk to system security through system security constraints on five solar farms (four in Victoria, one in New South Wales).
- System strength constraints in South Australia.
- Transmission outages and other network constraints.

As the system moves to higher penetrations of VRE, there is likely to be a level of VRE curtailment that is determined by the market to manage variability and uncertainty, as it relates to participant risk and risks to system security. While a full discussion on this topic is out of scope for the RIS, Section C5.1 provides a brief discussion on flexibility that can be provided by VRE to manage variability and uncertainty in the system, including curtailment and pre-curtailment.

Forecast vs unforecast ramp events

When prevailing conditions are known with a high degree of certainty and ramps are well forecast in advance, market participants and AEMO have enough time to respond to ensure that supply and demand remain in balance. From an operator perspective, under current frameworks, there is enough time to run assessments on the system and determine potential risks to resource adequacy and system security and then intervene if necessary.

As a system operator, it is incumbent on AEMO to maintain power system security. Under highly variable and uncertain conditions, the time available to the operator to run its assessments and intervene, if necessary, may be reduced. For example, if a large unforecast ramp becomes evident in the very near future, and the right resources are not already available, there may not be time for either the market to respond to the new information or for AEMO to intervene in the market to bring the required resources online. In this case, under the current regulatory frameworks, the only option may be to load shed.

If system conditions are highly variable and uncertain, market participants will operate their portfolios with these factors in mind and according to their respective risk appetites. However, there is no guarantee that participants' risk appetite in running their operations is aligned with the risk appetite of the system operator.

C3. Variability

This section covers the characterisation of ramps across the NEM regions over 5-minute and 1-hour ramp windows, historically and projected in 2025 under the Draft 2020 ISP Central generation build. It covers:

- Ramps in VRE resources, which include utility wind, utility solar, and DPV.
- The impact of geographic distribution on ramps.
- Ramps in net demand.

Key insights

- 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 installed VRE capacity in 2025) is projected to occur on 54 different days across the year, outside of predictable sunrise and sunset hours.
- A less variable supply of wind and solar can be achieved by locating wind and solar farms in diverse geographic locations.
- 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 net demand ramps (that is, ramps > 5.1 GW) will be driven predominantly by movements in VRE, which are typically more subject to uncertainty.
- Hourly net demand ramps are projected to be largest and fastest in winter months, during transition from the solar peak to the evening peak.

Variability relates to changes in supply and demand that would exist even with perfect foresight. Variability is characterised by magnitude (how large the change is) and window (the time it took the change to occur).

C3.1 Background

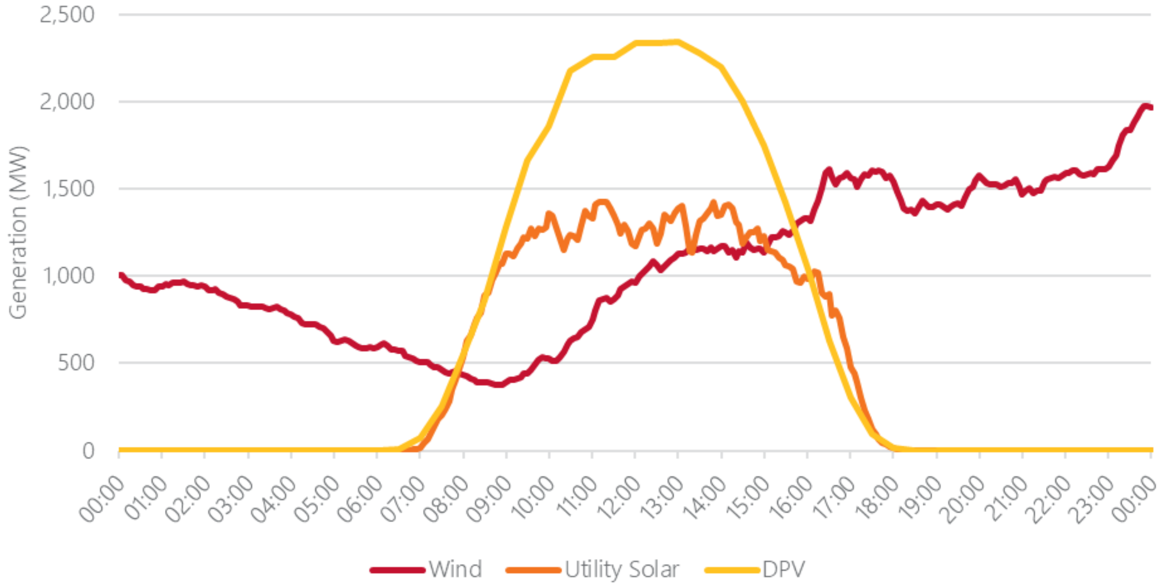
Variability at individual wind and solar farms is inherent, and is still a pervasive characteristic even when aggregated to a system-wide level, as shown in Figure 2. Figure 2 also shows that there are differences in the output pattern exhibited by wind and solar:

- Solar energy exhibits a diurnal pattern, following the rise and set of the sun. In addition, there is some stochastic variability throughout the day, largely related to passing clouds. DPV, taken in aggregate, tends to have a smoother profile than utility solar, due to the highly distributed nature of the systems.
- Wind energy can exhibit a weak diurnal pattern but is most typically influenced by larger weather systems combined with localised weather/terrain interactions.

Section C3.2 focuses on characterising variability in wind and solar (both utility solar and DPV), while Section C3.3 discusses the geographic diversity of utility wind and solar in the NEM.

The available output for VRE resources in the NEM, at any point in time, depends on the available wind and solar input, which are highly variable from one dispatch interval to the next. For semi-scheduled VRE resources, AEMO can limit the generator's output[19], but at other times the generator can supply any amount up to its maximum registered capacity. AEMO does not control the output of non-scheduled VRE resources and DPV in its dispatch process. Changes in these variable components may sometimes offset each other, reducing the variability observed in the system – or may simultaneously move in the same direction, creating a relatively larger change in the system.

Figure 2 NEM daily wind and solar profile example (Thursday, 25 April 2019)



Wind and solar data in this study contains aggregate information on semi-scheduled and non-scheduled wind and solar generators.

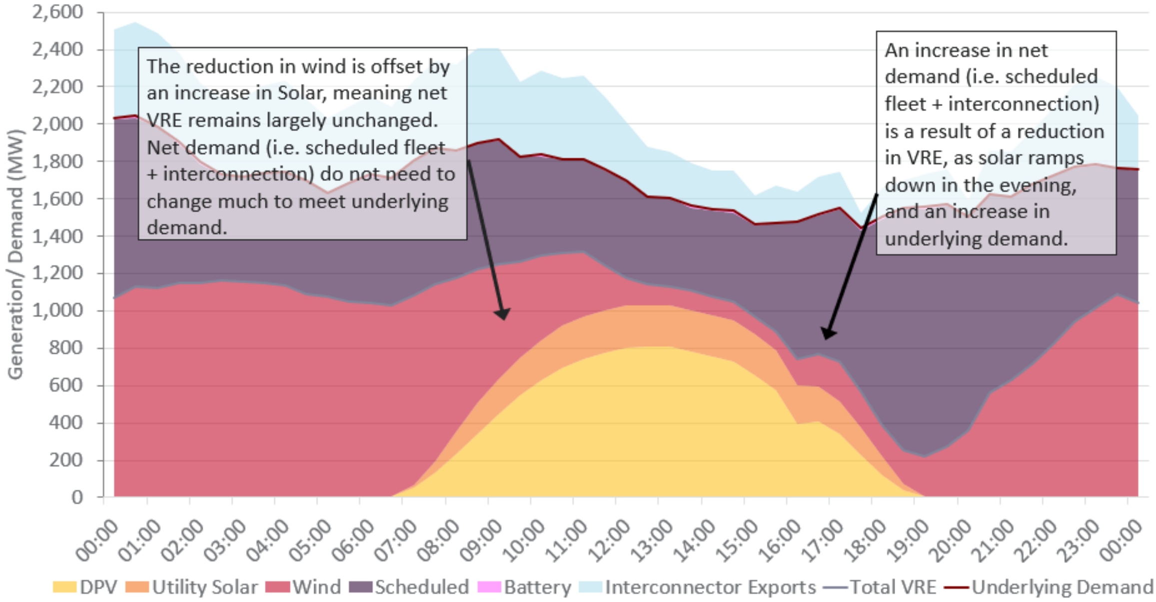
For the system to operate securely and reliably, energy supply and demand must always be balanced. To maintain the supply-demand balance, AEMO needs to schedule the remaining resources to meet an increasingly variable supply and demand.

Net demand represents the underlying demand portion that AEMO must meet with the scheduled generation sources only and not by wind or solar (including semi-scheduled and non-scheduled generators and DPV) resources. It also indicates the system flexibility that is required by the system to respond to both expected and unexpected changes in supply and demand.

Figure 3 shows an example of the daily requirements on the scheduled fleet and interconnectors (net demand) in South Australia to accommodate variability in VRE. More detail on net demand is in Section C3.4. The day presented in Figure 3 is also explored as a case study at the end of Section 5.1 in the RIS Stage 1 report.

[19] This may occur for a variety of reasons, including in response to network constraints for security purposes or if the unit is not economically cleared (that is they have priced their output at an above market clearing price.

Figure 3 South Australia daily net demand profile example (Saturday, 12 October 2019)



C3.2 Generation

C3.2.1 Overview

This section focuses on characterising ramps in **VRE resources**, which include **utility wind, utility solar, and DPV,** aggregated to a regional and NEM level over 5-minute and 1-hour ramp windows (assessed on a rolling basis)[20], historically and projected to 2025[21].

While several ramping windows, ranging from one minute to 90 minutes, were assessed as part of this study, only 5-minute and 1-hour windows are reported.

A case study on South Australia at the end of this section provides an insight into the nature of variability that has historically been accommodated in the NEM.

AEMO is progressing work to better understand the impact of the variable nature of wind and solar generation on maintaining frequency under normal operating conditions in the sub 5-minute timeframe. This work has been commissioned as part of the RIS program and will be released in a subsequent report.

Ramps are broken into upward and downward ramps:

- An **upward VRE ramp** is where the net output from all VRE resources increases over an interval (that is, over five minutes or one hour). An upward VRE ramp may be met by an equivalent upward ramp in underlying demand or reduction in output from scheduled generation to maintain the supply-demand balance. Downward flexibility in the scheduled fleet can be achieved by turning online scheduled or semi-scheduled generation down or off (subject to ramp rates), and may be facilitated by increasing exports or decreasing imports from the region experiencing the upward VRE ramp.
- A **downward VRE ramp** is where the net output from all VRE resources decreases over an interval. A downward VRE ramp may be met by an equivalent downward ramp in underlying demand or an increase in output from scheduled generation. Upward flexibility in the scheduled fleet can be achieved by turning online generation up (subject to ramp rates) or instructing offline generation to turn on (subject to

[20] Utility wind and solar figures include those farms classified as semi-scheduled and non-scheduled, where data is available.

[21] The 2025 scenario gives a view of potential production requirement on the conventional fleet, if wind, utility solar, and DPV across the NEM are uncurtailed.

start-up times) and may be facilitated by decreasing exports or increasing imports to the region experiencing the downward VRE ramp.

To maintain the supply-demand balance, an upward or downward ramp in VRE must be met by a movement in underlying demand or in the scheduled fleet. Meeting downward ramps in VRE is typically more challenging, particularly in situations where there is limited available capacity on online local generation or upward flexibility available on the interconnector.

C3.2.2 5-minute ramps

Table 2 lists summary statistics for 5-minute VRE ramps by year. A ramp is calculated as the net change in VRE output between the start and end of an interval (in this case, a 5-minute interval). For each of these intervals, the wind, utility solar, and DPV resources may be moving in the same or different directions. The yearly ramping distribution tends to be roughly symmetric (the occurrence of upward ramps of a given size is similar to the occurrence of downward ramps of that same size). Table 2 lists the average of the absolute ramp values (magnitude)[22], along with the maximum and 99th percentile ramps (split by upward and downward directions)[23]. The percent capacity values are calculated as the net change in VRE output expressed as a percentage of total online VRE capacity at the time of the ramp.

Key observations from Table 2 include:

- **The magnitude of 5-minute VRE ramps in the NEM is increasing.** As the installed capacity of VRE is forecast to grow between 2015 and 2025, so does the magnitude of ramps and the potential for them to impact system operation. For example, the largest downward 5-minute ramp in VRE recorded across the NEM in 2018 was -814 MW; however, by 2025, the largest equivalent ramp is projected to be -1,416 MW. This trend is evident when ramps are expressed in MW terms or relative to median yearly installed capacity.
- **The maximum upward and downward ramps are significantly larger than their comparative 99th percentile ramps.** For example, in 2018, the maximum upward ramp was 897 MW (14.73%), however drops to 136 MW (2.23%) at the 99th percentile. This means that throughout 2018, there was 1% (that is, just above 1,000 5-minute intervals) of ramps that were larger than 136 MW.

Table 2 VRE 5-minute ramp statistics in the NEM

	Average		Maximum				99th Percentile			
	MW	% of capacity	Upward (MW)	% of capacity	Downward (MW)	% of capacity	Upward (MW)	% of capacity	Downward (MW)	% of capacity
2015[A]	20	0.57%	360	10.25%	-483	-13.77%	89	2.53%	-92	-2.61%
2016	26	0.61%	772	17.87%	-782	-18.11%	98	2.27%	-107	-2.48%
2017	30	0.60%	256	5.08%	-300	-5.97%	112	2.24%	-123	-2.45%
2018	37	0.61%	897	14.73%	-814	-13.36%	136	2.23%	-151	-2.49%
2025	123	0.87%	1,008	7.10%	-1,416	-9.96%	480	3.38%	-685	-4.82%

A. DPV information is included in the dataset from 1 August 2015, so is only partial in the 2015 figures.

It is also important to consider the growth in 5-minute ramps on a regional basis, particularly those regions at the extremities of the NEM – Queensland, South Australia, and Tasmania. This is important because, over these short timeframes, the system relies on online local generation and interconnector headroom to maintain the supply-demand balance. In less connected regions, there is an increased risk of insufficient online reserves to cover short-term deviations.

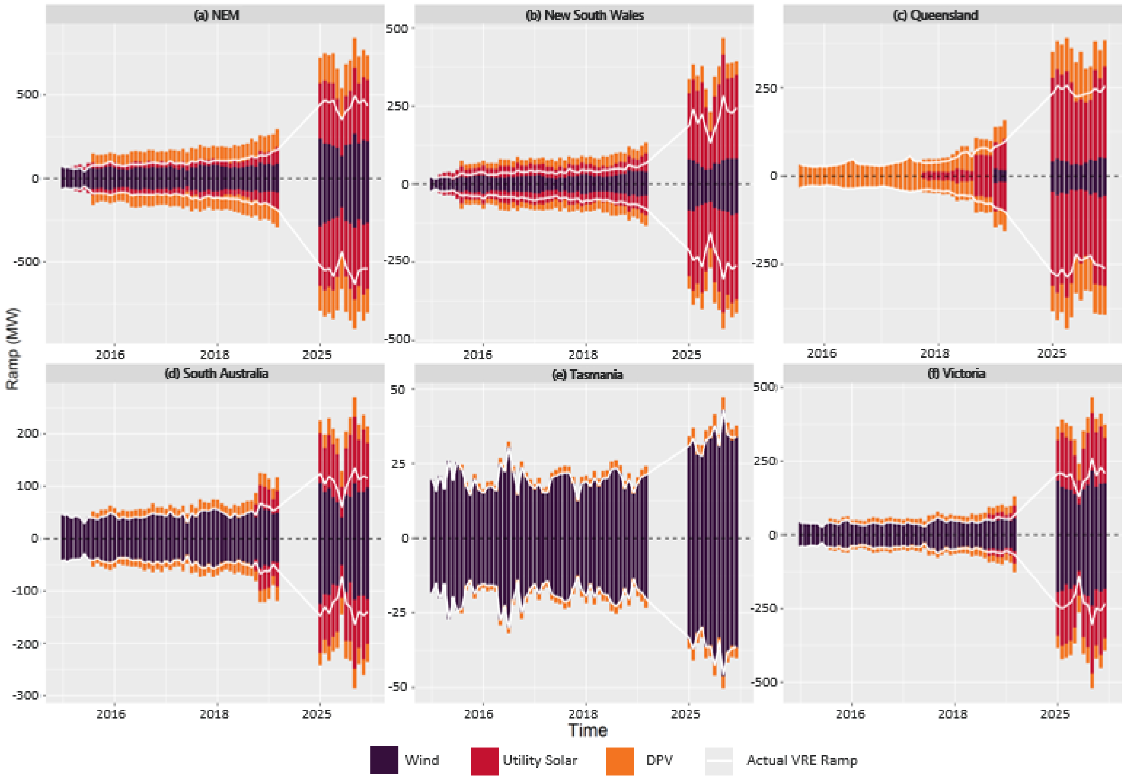
[22] That is, removal of negative signs, so all ramp magnitudes across the distribution can be compared.

[23] See the supplementary materials section (Section C7) for an overview of statistical concepts, including standard deviation and percentiles.

The supplementary materials section (Table 14) presents regional summary statistics for 5-minute ramps in VRE. The three observations discussed above also hold on a regional basis. For example, in Queensland, the largest 5-minute downward ramp projected in 2025 is -695 MW (16.02%). This is an increase in magnitude from the maximum downward ramp of -268 MW (11.73%) observed in 2018. Further, the magnitude of the projected 2025 99th percentile ramp is -238 MW (5.84%), which is similar in magnitude to the maximum downward ramp observed in 2018[24]. This means that under the assumption of full utilisation of wind and solar generation under the Draft 2020 ISP Central scenario generation build out to 2025, **there are over 1,000 5-minute ramps in Queensland in 2025 that are projected to be larger than the 2018 maximum**.

Figure 4 presents a view of how 5-minute ramps have changed between 2015 and 2019, and how they are projected to change by the year 2025.

Figure 4 Butterfly plot: monthly top 99th percentile upward and downward 5-minute VRE ramps in the NEM



Interpreting butterfly plots

The butterfly plots show the monthly 99th percentile ramp between 2015 to 2019 and projected for 2025 (calendar years). These are the values that are exceeded in only 1% of cases. The **coloured bars** are the monthly 99th percentile ramp observed in each region for different VRE types (wind, utility solar and DPV). Stacked together they represent the top 1% theoretical ramp for a region if all VRE types had their 99th percentile ramp simultaneously. The **white (net ramp) line** represents the observed monthly 99th percentile ramp that resulted from the overall movement in wind, solar and DPV.

Key observations from Figure 4 include:

- **Ramps at the 99th percentile have been increasing historically and are projected to continue rising, as more VRE capacity is added to a region**[25].

[24] Note, the 99th percentile for 5-minute downward ramps in Queensland in 2018 was -57 MW.

[25] See Figure 1 for a view on how installed capacity in the NEM is changing over time.

- Diversity between VRE technologies (that is between wind, utility solar, and DPV) means that **although ramps are increasing in magnitude, these increases are smaller compared to the growth in installed capacity.** As installed capacity increases, there is an increase in the observed 99th percentile ramp in the region (the white line trending up), however, this increase is not proportional to the growth in theoretical maximum ramp (the stacked colour bars). The more diversity in a region, the larger this gap. Victoria appears to have the most diversity by 2025, with the most equal projected ramps from each technology type and the largest distance between the net ramp (white line) and theoretical top % ramp (sum of stacked coloured bars).

C3.2.3 1-hour ramps

Table 3 shows the summary statistics for 1-hour VRE ramps in the NEM by year[26]. These hourly ramps are calculated as overlapping hourly intervals at a 5-minute granularity. For example, the hourly window from 01:00 to 02:00 is assessed, then 01:05 to 02:05, and so on. Although the same **overarching trends are observable for the 1-hour ramp window as the 5-minute window** discussed in Section C3.2.2, there are some key observations worth noting:

- **Ramp magnitude over a 1-hour window (Table 3) are larger** than the corresponding values for the 5-minute window (Table 2).
- **The rate of change for larger ramps over the 1-hour window are lower than the 5-minute window.**
  - If the 5-minute ramps are standardised to hourly values, it is evident that ramp rates over a 5-minute period can be very high compared to longer duration ramps. For example, the maximum upward and downward ramps in 2018 for the 1-hour period were 1,689 MW and -1,923 MW respectively. If the corresponding 5-minute ramps were converted to the same hourly timeframe, the ramp would be 10,764 MW (177% of capacity) and -9,769 MW (160% of capacity).
  - **The degree of variability in the hourly ramps is somewhat masked**. On average, hourly ramp rates are slower, however they may contain intervals of very high ramp rates. Wind and solar may move up and down within the hourly window (that is, they may reverse for small periods of time in an overall upward or downward trajectory).

Table 3 VRE 1-hour ramp statistics in the NEM

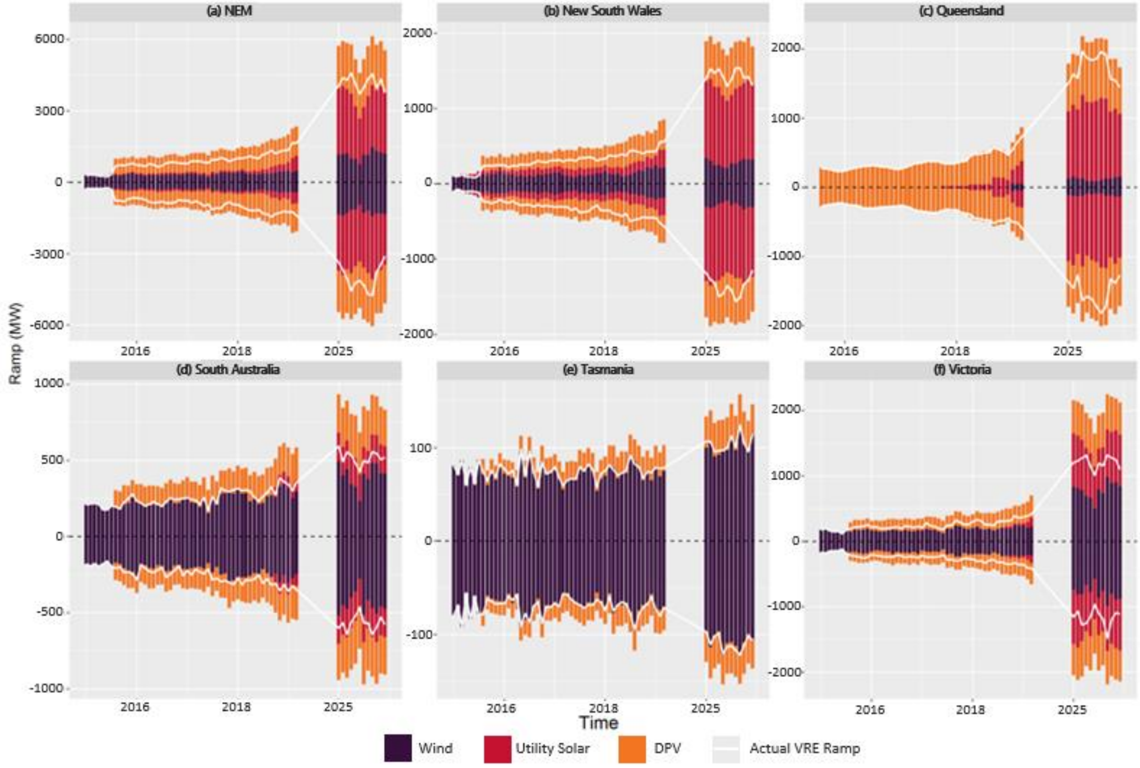
	Average		Maximum				99th Percentile			
	MW	% of Capacity	Upward (MW)	% of Capacity	Downward (MW)	% of Capacity	Upward (MW)	% of Capacity	Downward (MW)	% of Capacity
2015[A]	139	2.53%	1,581	19.94%	-1,090	-14.12%	701	8.87%	-717	-9.05%
2016	229	2.75%	1,845	23.18%	-1,283	-15.26%	816	9.41%	-886	-10.25%
2017	273	2.86%	1,512	14.67%	-1,421	-14.59%	986	9.57%	-1,045	-10.15%
2018	347	2.97%	1,689	13.80%	-1,923	-18.32%	1,267	9.61%	-1,361	-10.31%
2025	1016	3.85%	5,773	21.85%	-5,826	-21.98%	4,486	16.91%	-4,471	-16.87%

A. DPV information is included in the dataset from 1 August 2015, so is only partial in the 2015 figures.

Figure 5 is a reproduction of the butterfly graph shown in Figure 4 for 1-hour ramps.

[26] The regional summary statistics for 1-hour ramps are available in the supplementary materials section (Table 14)

Figure 5 Butterfly plot: monthly top 99th percentile upward and downward 1-hour VRE ramps in the NEM



Note: DPV information is included in the dataset from 1 August 2015.

The same trends are evident for the 1-hour ramps as for the 5-minute ramps, noting that:

- The **ramp magnitudes are larger for the 1-hour ramp window compared to the 5-minute window**.
- The relative influence of different technology types remains relatively consistent between 5-minute and 1-hour ramps. This is shown by the similar proportions of wind, utility solar, and DPV (coloured bars) in Figures 4 and 5. However, **movements in DPV feature more prominently over the 1-hour window, compared to the 5-minute window**. The diverse nature of DPV means location-specific variability over a 5-minute period tends to smooth out when aggregated regionally. This effect is less prominent for utility-scale resources, because large farms built in a single location are affected by similar local weather patterns and there is less installed capacity across the region to smooth the variability.

AEMO is responsible for system operation in the NEM, and as such is interested in large magnitude ramps that are more likely to pose challenges in the system. An alternative to looking at percentiles to identify large ramps is to look at ramps that are above a capacity threshold.

Table 4 displays the numbers of large VRE ramps with magnitudes greater than 10%, 20%, and 30% of the median yearly installed capacity of VRE. The number of total occurrences and the number of days these were recorded on are both reported, as there may be many occurrences within a single day (these may be part of a single event or a high variability day).

The extreme ramp events discussed in this section are events that are at the tail ends of the distribution of ramps in the NEM; that is, they are 'statistically extreme'. While an event may have a large magnitude and ramp rate, it is not necessarily an 'operationally extreme' or reportable event. **Typically, operationally extreme events related to ramping in VRE are also associated with extenuating operational circumstances that are exacerbated by the ramping event**, for example, a combination of forecasting error, unplanned outages, or large movements in underlying demand.

Table 4 Extreme 1-hour VRE ramp events in the NEM

	Threshold (MW)			Total occurrences (n)			Days (n)		
	10%	20%	30%	10%	20%	30%	10%	20%	30%
Upward ramp events									
2015	361	722	1,083	456	3	-	73	2	-
2016	835	1,671	2,506	381	1	-	61	1	-
2017	955	1,910	2,865	649	-	-	100	-	-
2018	1,175	2,350	3,526	932	-	-	126	-	-
2025	2,646	5,291	7,937	6,579	22	-	356	6	-
Downward ramp events									
2015	361	722	1,083	474	-	-	69	-	-
2016	835	1,671	2,506	844	-	-	100	-	-
2017	955	1,910	2,865	1,056	-	-	130	-	-
2018	1,175	2,350	3,526	1,521	-	-	160	-	-
2025	2,646	5,291	7,937	5,441	37	-	349	11	-

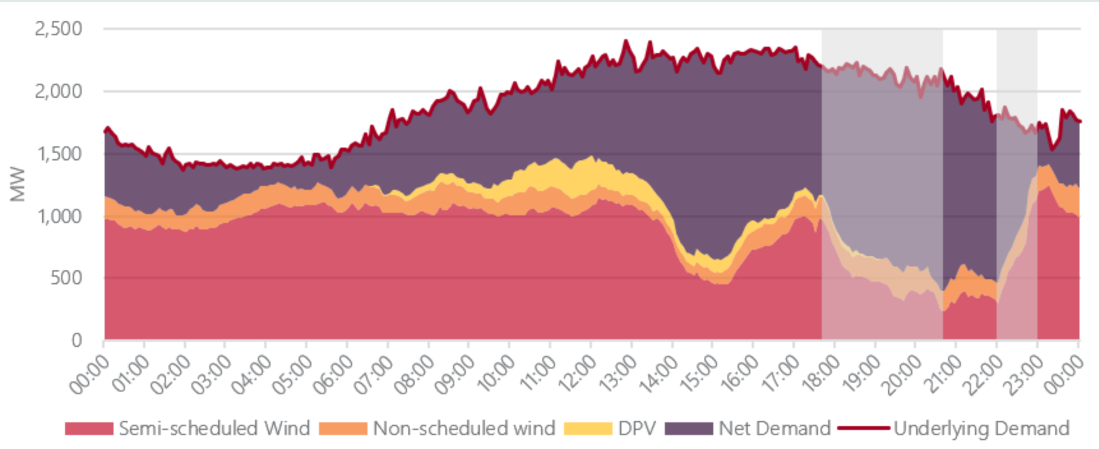
This Appendix includes discussion on the following areas, to provide insight into events that have the potential to be operationally challenging:

- **Section C3.4** provides understanding of movements in underlying demand relative to wind and solar.
- **Section C4** discusses uncertainty with respect to forecast variance and its impact on system operation.

Case study | South Australia | Monday, 18 December 2017

This event was characterised by a wind change due to a large low-pressure system that moved east across the state throughout the day; the general wind direction shifted from north-westerly to south-westerly. It occurred during a high electricity demand period, as temperatures ahead of a front reached 35°C in Adelaide. The VRE ramp of 941 MW at 22:00 was the most severe 1-hour upward ramp in South Australia for 2017. Figure 6 shows the profile of the day with a 5-minute resolution.

Figure 6 Generation and net demand profile

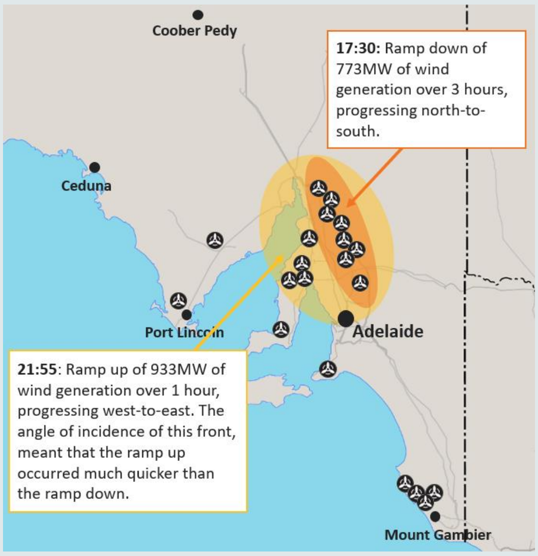


To contextualise this event, it is worth noting that:

- Peak wind generation on the day was 1,357 MW at 23:20, corresponding to the upward ramp event.
- Peak South Australian operational demand was 2,274 MW at 16:30, just prior to the downward ramp event.

A pre-frontal trough resulted in a reduction of 755 MW of wind generation over three hours between 17:35 and 20:35, progressing north-to-south as illustrated in Figure 7 (orange area). This represented 42% of total South Australian installed wind capacity and 56% of peak wind for the day.

Figure 7 South Australia wind farm locations



As the front moved east, bringing with it stronger south-westerly winds, an increase of 941 MW across 1 hour between 22:00 and 23:00 was observed. This represented 52% of total South Australian installed wind capacity and 69% of peak wind for the day. The angle of incidence of this front north of Adelaide (Figure 7, yellow area) meant that more wind farms were affected simultaneously, such that the ramp up event occurred much quicker than the ramp down.

This case study is continued in Section C4.2 (uncertainty) of this Appendix.

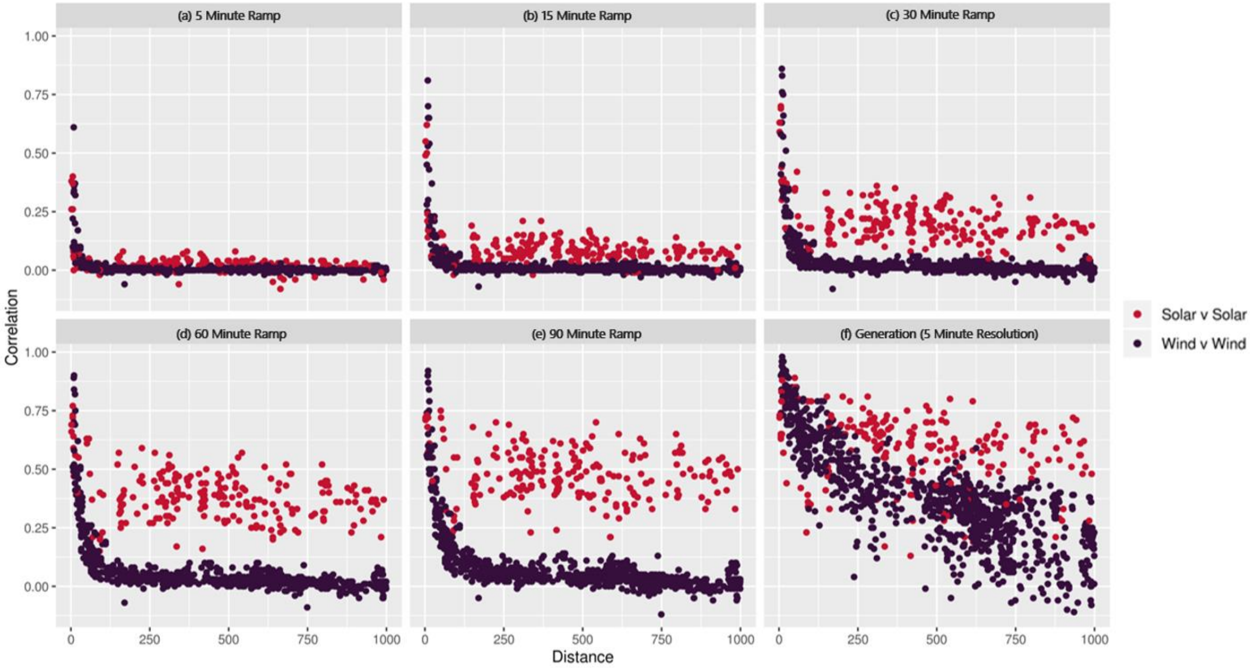
C3.3 Geographic distribution

The trend of increasing variability (magnitude and rate of change) across the NEM is dependent on the increasing penetration of wind and solar. However, the proximity of farms to each other also plays a role in the degree of variability that is introduced into the system. As shown in Figures 4 and 5, there is some evidence of diversity between wind and solar farms in the system that, at times, may offset each other to reduce the net amount of variability experienced in the system. When assessing variability in a future 2025 scenario, there is a need to consider the impact of geographic diversity in smoothing the aggregate change in output from wind and solar farms at a regional and aggregate level.

Figure 8 shows the Pearson correlation coefficient between historic wind farms and solar farms (utility-scale only) that are within 1,000 km across the NEM[27]. Panel (f) shows the correlation trend for normalised wind and solar 5-minute **generation** across the NEM. Panels (a) to (e) show the correlation trends for generation **variability** over different time windows.

[27] See the supplementary materials section for pairwise correlation by distance for farms within 250 km in the NEM (zoomed in image of Figure 27).

Figure 8 Pairwise correlation by distance (historic, 2015-18)



The **Pearson correlation coefficient** measures the strength of the linear relationship between two variables. It ranges between -1 and 1, where a coefficient of 1 indicates a perfect upward linear relationship.

Four key insights are demonstrated by Figure 8[28]:

- **As distance increases, generation and variability become less correlated between farms**. However, correlation in *variability* between farms erodes much faster than correlation in *generation*. So, while farms that are reasonably close together may have generation that is well correlated, this does not mean their variability will also be well correlated. For example, wind farms that are situated close together may both experience high wind days, however local wind gusts may cause the farms to experience ramps at different times.
- For wind farm pairs and solar farm pairs, **the shorter the ramp window, the smaller the farm separation distance required for the farms' variability to become uncorrelated**. This is supported by Table 5, which shows the average correlation coefficient for farms across different ramp windows and distances boundaries. For example, for pairs of wind farms to see an average correlation coefficient below 0.3, they need to be spaced greater than 15 km apart for 15-minute ramps, greater than 30 km apart for 30-minute ramps, and greater than 100 km for 90-minute ramps. These trends are also evident in the future 2025 dataset, with results presented in the supplementary materials section (Figure 27).
- **Variability and generation of solar farm pairs tend to be more correlated over longer distances, compared to wind farm pairs**. For example, solar farm pairs within 500 km of each other have an average correlation coefficient of 0.50 for a 90-minute ramp, compared to 0.14 for wind farm pairs. The lower correlation between wind farm pairs over longer distances illustrates the value of building wind farms in different parts of the NEM, as the output and variability at these less correlated farms are more likely to offset each other, resulting in a smoother output from the aggregate wind fleet. This smoother output is easier to predict and easier to manage in dispatch.

  The larger correlation coefficients between solar farm pairs over longer distances may be driven by the diurnal output pattern exhibited by solar resources. Despite this, Figure 8 and Table 5 still indicate that is

[28] See also Figure 26 in the supplementary materials section for a zoomed in view of Figure 8.

beneficial to have diverse geographic distribution of solar farms across the NEM, as farms still become less correlated as distance increases.

- **Wind and solar tend to have an offsetting effect, even at close distances.** As indicated in Table 5, most correlation coefficients are near or below zero, indicating a weak inverse relationship between solar and wind farm production and variability.

Table 5 Average pairwise correlation for historic farms

	5-min ramp	15-min ramp	30-min ramp	60-min ramp	90-min ramp	5-min generation
Wind v wind						
< 15 km	0.20	0.40	0.52	0.63	0.68	0.89
< 30 km	0.14	0.28	0.40	0.53	0.59	0.85
< 100 km	0.05	0.10	0.16	0.25	0.31	0.71
< 500 km	0.02	0.04	0.06	0.11	0.14	0.54
Solar v solar						
< 15 km	0.19	0.38	0.51	0.64	0.69	0.71
< 30 km	0.17	0.34	0.47	0.61	0.66	0.69
< 100 km	0.09	0.21	0.34	0.50	0.57	0.64
< 500 km	0.03	0.11	0.23	0.41	0.50	0.61
Solar v wind						
< 15 km	-0.02	-0.04	-0.07	-0.10	-0.11	-0.15
< 30 km	-0.02	-0.04	-0.06	-0.10	-0.13	-0.18
< 100 km	-0.01	-0.02	-0.03	-0.06	-0.08	-0.12
< 500 km	0.00	-0.01	-0.03	-0.05	-0.06	-0.11

- **A less variable supply of wind and solar can be achieved by locating wind and solar farms in diverse geographic locations.** As the output from these farms is driven by large-scale weather systems combined with localised weather and terrain interactions, there is a greater probability that farms far apart will offset each other's variability and provide a smoother aggregate output. Conversely, placing farms of the same technology type (such as many wind farms) within 15 km of one another will increase the probability of their output and variability being strongly positively correlated[29]. This would increase the likelihood of coincident ramping across multiple farms, leading to ramping events of greater magnitude and ramp rate.

C3.4 Net demand

C3.4.1 Overview

For the system to operate securely and reliably, **energy supply and demand must always be balanced.** To maintain the supply-demand balance, AEMO needs to schedule the remaining resources to meet an increasingly variable supply and demand.

[29] Some wind farms span terrain across distances greater than 15 km and there is some evidence of diversity within these large farms.

Net demand represents the underlying demand portion that AEMO must meet with the scheduled generation sources only, and not by wind or solar (including semi-scheduled and non-scheduled generators and DPV) resources. It also indicates the **system flexibility** that is required by the system to respond to both expected and unexpected changes in supply and demand.

Three key changes to the **shape of the net demand profile** are emerging as a result of increased wind and solar. These can be seen in Figure 9, which displays some typical profiles by season:

- **Faster, steeper ramps** – particularly when VRE and underlying demand move in opposite directions, the magnitude and rate of change of a ramp event has the potential to be much greater.
- **Lower mid-day trough** – scheduled generation must operate at lower levels (or fewer units may be online) during the middle of the day, when DPV and utility solar are operating at peak output. As the midday trough falls to lower levels, the ramp towards the evening peak (as the sun is setting) becomes much larger and steeper.
- **Changing daily peaks** – shorter and smaller morning peak and a later evening peak, due to solar.

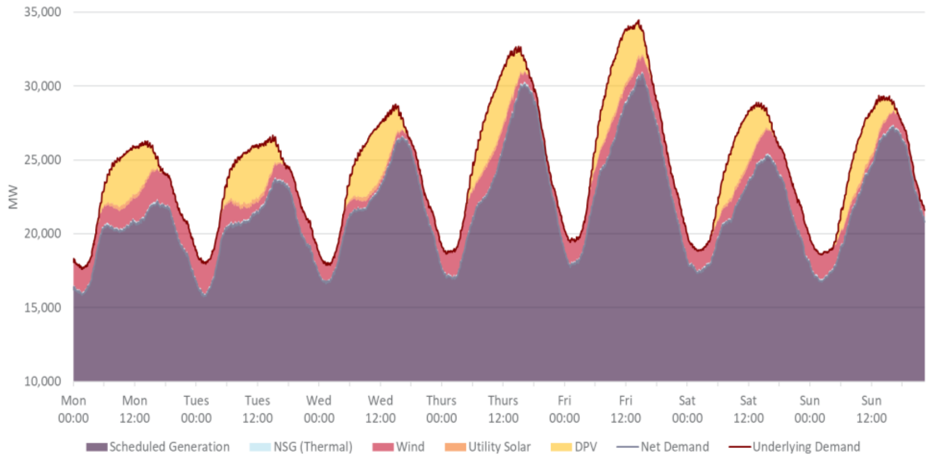
These factors place additional requirements on scheduled generators (or other flexible resources) to react quickly to meet expected dispatch levels, start up with short notice, sustain faster ramp rates over longer durations, and provide more cycling throughout the day.

Underlying demand in this report means all electricity demand that is met by local scheduled, semi-scheduled, non-scheduled generation and distributed solar PV generation, and by interconnector imports to the region.

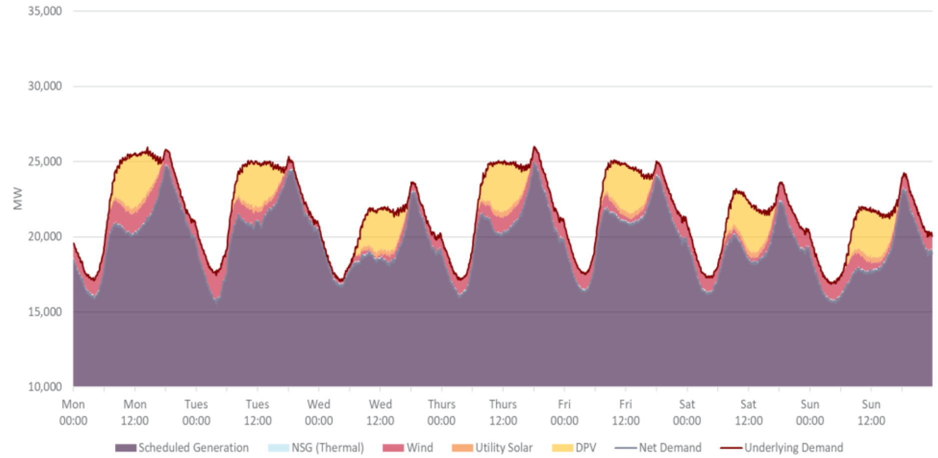
Net demand means underlying demand net of VRE generation, that is, demand that must be met by scheduled generation sources and not by wind or solar (including utility solar and DPV resources).

Figure 9 Typical seasonal demand profiles

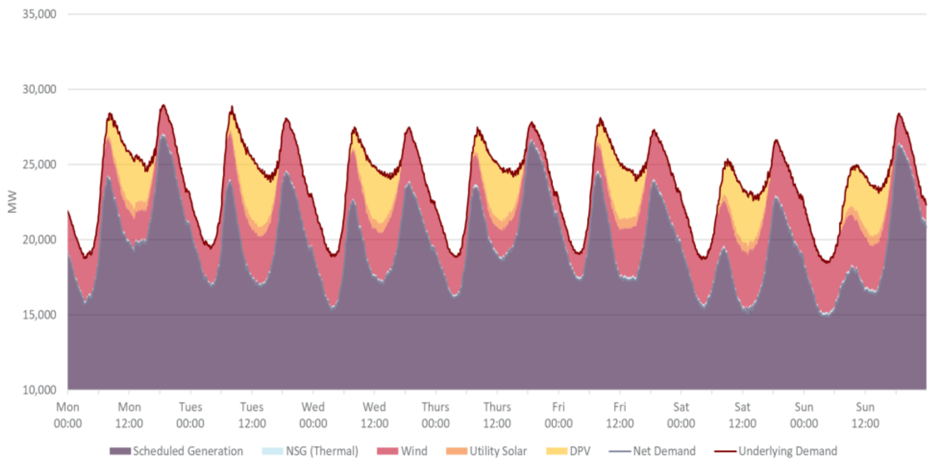
(a) Summer



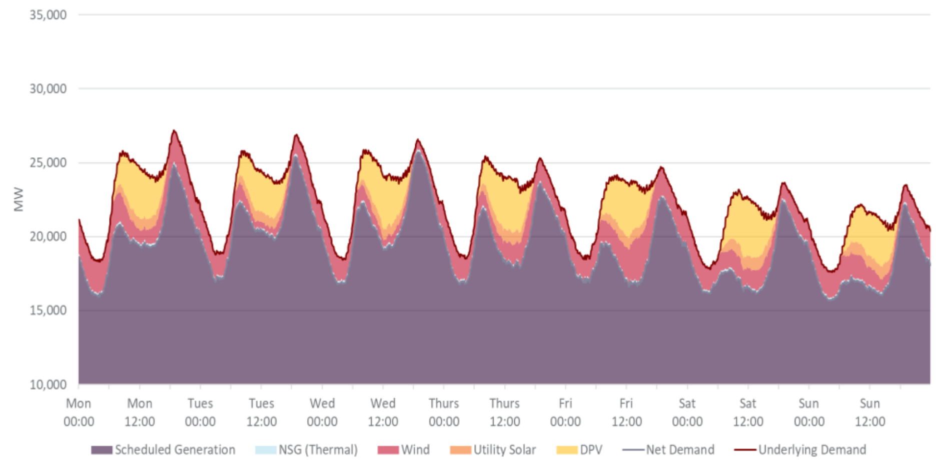
(b) Autumn



(c) Winter



(d) Spring



C3.4.2 1-hour net demand ramps

Table 6 displays statistics of 1-hour net load ramps (magnitude only) across the NEM[30,31]. These ramps are the net outcome of movements in wind, utility solar, DPV, and underlying demand. Table 6 shows that the **magnitude of hourly net demand ramps is projected to increase significantly to 2025**, evident across the whole distribution of net demand ramps, not just the maximum upward and downward ramps.

Table 6 NEM 1-hour net demand ramp statistics

	Average	Maximum		99th Percentile	
	MW	Upward (MW)	Downward (MW)	Upward (MW)	Downward (MW)
2015	780	4,189	-2,196	3,416	-1,720
2016	777	4,062	-2,290	3,264	-1,741
2017	808	4,043	-3,020	3,322	-1,812
2018	832	4,240	-2,402	3,398	-1,832
2025	1,174	6,147	-4,682	5,105	-3,457

Table 7 shows hourly ramps for the constituent elements that affect net demand. The maximum upward and downward hourly ramps in underlying demand are not projected to change significantly out to 2025. However, there is a significant growth in hourly ramps for wind, utility solar, and DPV. The growth in utility solar is particularly stark, with the maximum upward hourly ramp projected to increase from 635 MW in 2018 to 3,014 MW by 2025.

The projected growth in net demand ramps is not proportional to forecast growth in the ramps of its constituent elements, as all elements do not necessarily experience their maximum ramp simultaneously. Ramps in net demand may also be larger or smaller than underlying demand, depending on the relative movement in VRE at the time.

Table 7 NEM statistics of 1-hour underlying demand and net demand ramps

	Maximum upward ramp (MW)					Maximum downward ramp (MW)				
	Underlying demand	Wind	Utility solar	DPV	Net demand	Underlying demand	Wind	Utility solar	DPV	Net demand
2015	2,871	843	94	710	4,189	-1,731	-590	-98	-693	-2,196
2016	2,998	634	111	825	4,062	-2,106	-582	-106	-944	-2,290
2017	3,209	873	145	977	4,043	-2,096	-573	-150	-1,010	-3,020
2018	3,661	911	635	1,238	4,240	-1,960	-685	-612	-1,247	-2,402
2025	3,292	2,313	3,014	2,214	6,147	-2,145	-2,339	-3,129	-2,312	-4,682

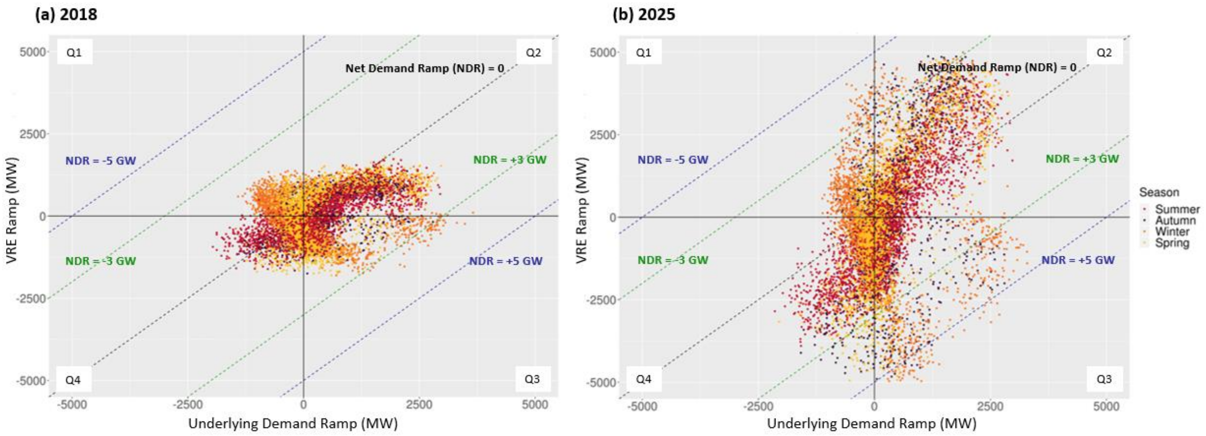
Figure 10 is a scatterplot of underlying demand and VRE hourly ramps, using 2018 data (Panel (a)) and projected 2025 data (Panel (b)). Ramps are also split into seasons by colour. Figure 10 shows:

[30] This section focuses on 1-hour net demand ramps only; 5-minute net demand ramps have been omitted due to insufficient data granularity for demand in the projected 2025 year.

[31] 1-hour net demand ramp statistics are presented on a regional level in the supplementary materials section (Table 18).

- **The relative movement of underlying demand compared to VRE remains constant going forward** – this is supported by the relative distribution of the data points in the quadrants between 2018 (panel A) and 2025 (panel B). Panel A shows that in 2018 61% of ramps were in the second (Q2) and fourth quadrants (Q4) and 39% in the first (Q1) and third quadrants (Q3). In Panel B for 2025, 64% of observations are in Q2 and Q4, while 36% are in Q1 and Q3.
- **In winter months, underlying demand and VRE are most likely to ramp in opposite directions on an hourly basis, meaning the scheduled fleet will need to work harder in these months to cover deviations in net demand** – this is supported by the distribution of points between the quadrants, compared on a seasonal basis. Summer, autumn, and spring have most points in Q2 and Q4[32], while winter has slightly more points in Q1 and Q3 (2018: 58%, 2025: 53%). Figure 9 shows weekly demand profiles across the seasons, which supports the observations in Figure 10.
- **VRE is projected to be a significant driver of ramps in net demand by 2025** – Figure 10 shows the change in the difference in shape between 2018 and 2025, which is indicative of a change in key driver behind net demand ramps.
  - In 2018, ramps in VRE are greater than ramps in underlying demand 52% of the time. By 2025, VRE ramps are projected to have grown to the point where they are larger than underlying demand ramps 83% of the time.
  - In 2018, the top 1 % of net demand ramps (ramps > 3.4 GW) were driven by movements in underlying demand which is largely predictable. By 2025 the top 1 % of net demand ramps (ramps > 5.1 GW) will be driven predominantly by movements in VRE, which are typically more subject to uncertainty.

Figure 10 Changes in 1-hour underlying demand and VRE



Interpreting net demand scatter plots

Data points in **Q2 and Q4** represent times when both underlying demand and net VRE move in the same direction. In these quadrants, VRE and underlying demand offset one another, reducing the requirements on the scheduled fleet to cover the net load variability. Points in **Q1 and Q3** represent times when underlying demand and aggregate VRE move in opposite directions. 1-hour ramps in underlying demand are plotted on the **horizontal axis** (e.g. points in Q1 and Q4 indicate a downward ramp in underlying demand). 1-hour ramps in VRE are plotted on the **vertical axis**. The dotted lines represent the **locus of net demand ramps**. The black line indicates a net demand ramp of zero. The green and blue lines show ±3 GW and ±5 GW changes in net demand, respectively.

[32] In 2018, summer, autumn, and spring have 74%, 62%, and 60% of points in Q2 and Q4. In 2025, summer, autumn, and spring have 74%, 61%, and 70% of points in Q2 and Q4.

Failure to forecast these large changes in VRE (and subsequent net demand requirements) could prove operationally difficult. It is important for AEMO to better understand the uncertainty associated with VRE fluctuations, so the system can be appropriately managed as new operating conditions emerge.

Case study | NEM | Comparison of largest hourly upward net demand ramps in 2018 and 2025

Figure 11 depicts one of the largest 1-hour net demand ramps that occurred across the NEM in 2018, which was on Sunday, 22 July 2018, in the evening between 17:00 and 18:00. The magnitude of this ramp was 3,770 MW. The major contributor to this ramp was an increase in underlying demand of 2,996 MW. Utility solar and DPV ramped down by -164 MW and -547 MW as the sun was setting and wind also ramped down -62 MW. The movement in VRE in the opposite direction to the change in underlying demand meant that the size of the net demand ramp to be covered by the scheduled fleet was larger.

Figure 11 Net demand ramp in 2018

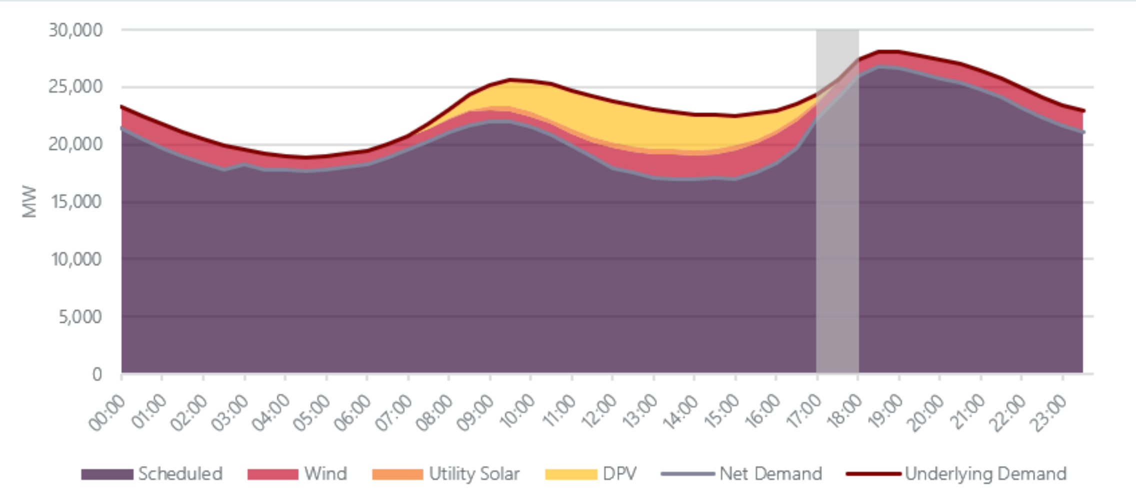
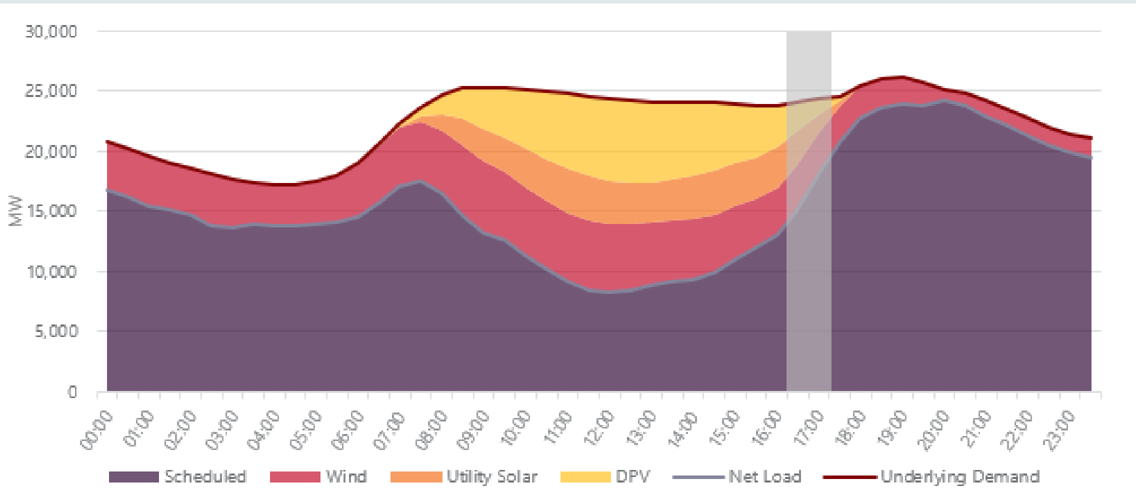


Figure 12 shows the daily profile for the largest projected 1-hour net demand ramp across the NEM in 2025. The largest ramp is projected to occur on a Monday in winter between 16:30 and 17:30 with a magnitude of 6,147 MW. The nature of this ramp is very different to that observed in Figure 11. The change in underlying demand is smaller, increasing by 1,052 MW. The movements in VRE, however are much more significant. Utility solar and DPV ramp down by -2,407 MW and -1,934 MW, respectively, over the hour. Wind also ramps down by -752 MW. So, although the mechanics creating the net load ramp are the same between the 2018 and 2025 examples, the changes in VRE in the 2025 example are at a much larger scale.

As shown in Table 7, none of these downward ramps are the largest predicted for that particular technology in 2025, however all VRE technologies ramp coincidently in the same direction, creating a need for the scheduled fleet to increase to balance supply and demand. To enable a consistent and appropriate response to events such as the one depicted in Figure 12, the scheduled fleet will need to have sufficient flexibility and be supported by appropriate operational and market enhancements.

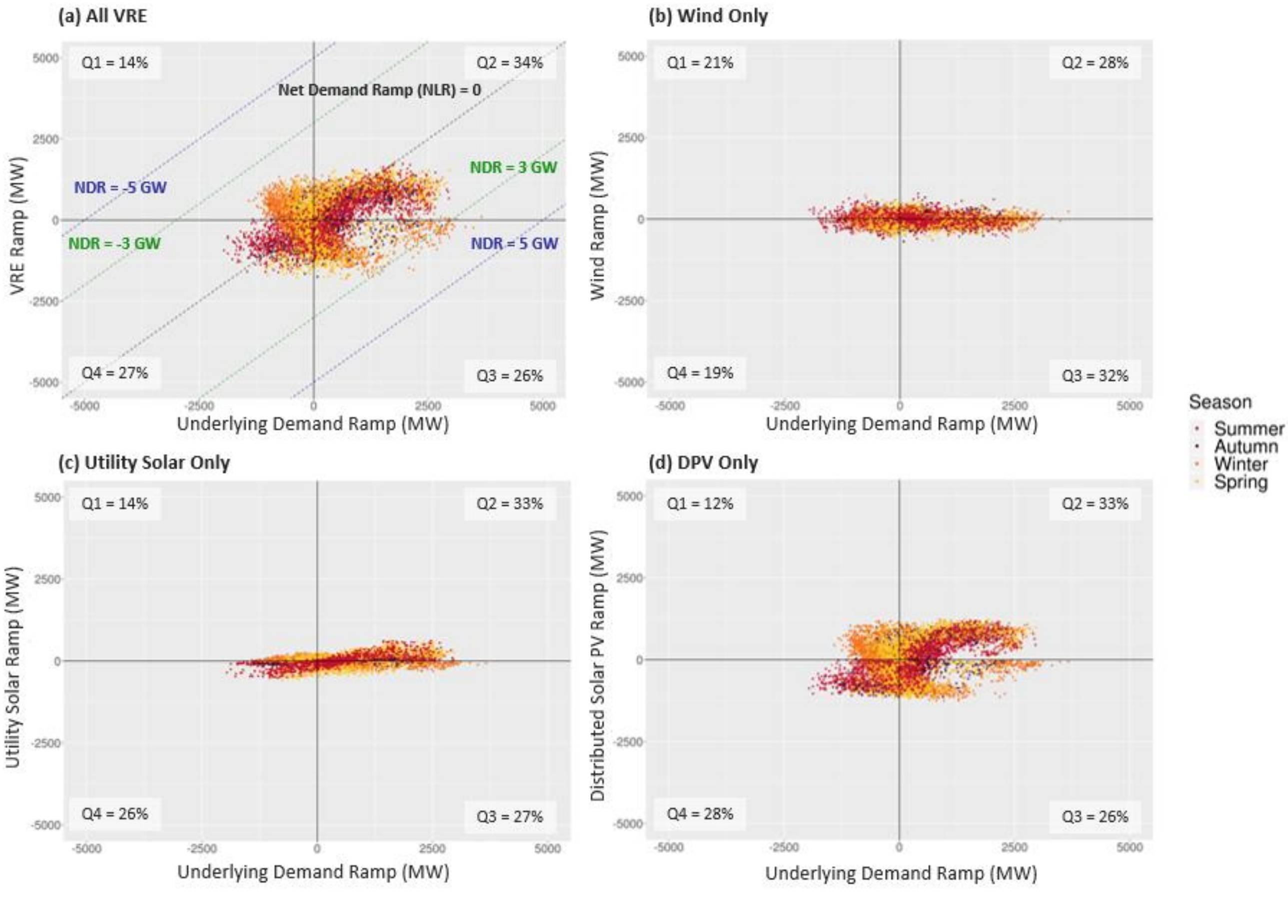
Figure 12 2025 largest 1-hour net load ramp



C3.4.3 Drivers of net demand

As described in the case study above, there can be different factors that influence the net demand curve. Figures 13 and 14 revisit the plots presented in Figure 9, for 2018 and 2025, respectively, with the addition of net demand drivers. Panels (B), (C), and (D) compare 1-hour underlying demand ramps to 1-hour ramps in utility wind, utility solar, and DPV, respectively. These panels are illustrative of how VRE technologies inform the distribution of points in Panel (A). Note that for any ramp presented in Panel (A), the contributing drivers may be ramping in the same direction or be offsetting each other. Thus, the points in Panels (B), (C), And (D) are not directly translatable to the data presented in Panel (A)[33]. For example, in Section C3.3 it was observed that solar and wind resources are largely uncorrelated, so are more likely to offset each other at times.

Figure 13 Changes in 1-hour underlying demand and VRE in 2018, including drivers



Note: percentages values shown represent the proportion of points that fall within each quadrant.

In Section C3.4.3, it was observed that in 2018 ramps in net demand were largely driven by changes in underlying demand. By separating out the individual components of VRE ramps, the following insights can be deduced from Figure 13:

- **Utility solar and DPV tend to ramp in the same direction as underlying demand over 1-hour windows** – panels (C) and (D) show more points in Q2 and Q4[34], indicating that these technologies tend to ramp in the same direction to underlying demand more than half of the time. There are, however, some **seasonal variations** in this trend, which are largely attributable to the different timing of sunrise and sunset. Utility

[33] Also note that for Panels (B), (C), and (D), an x=y line through the origin is not equivalent to a zero net demand ramp.

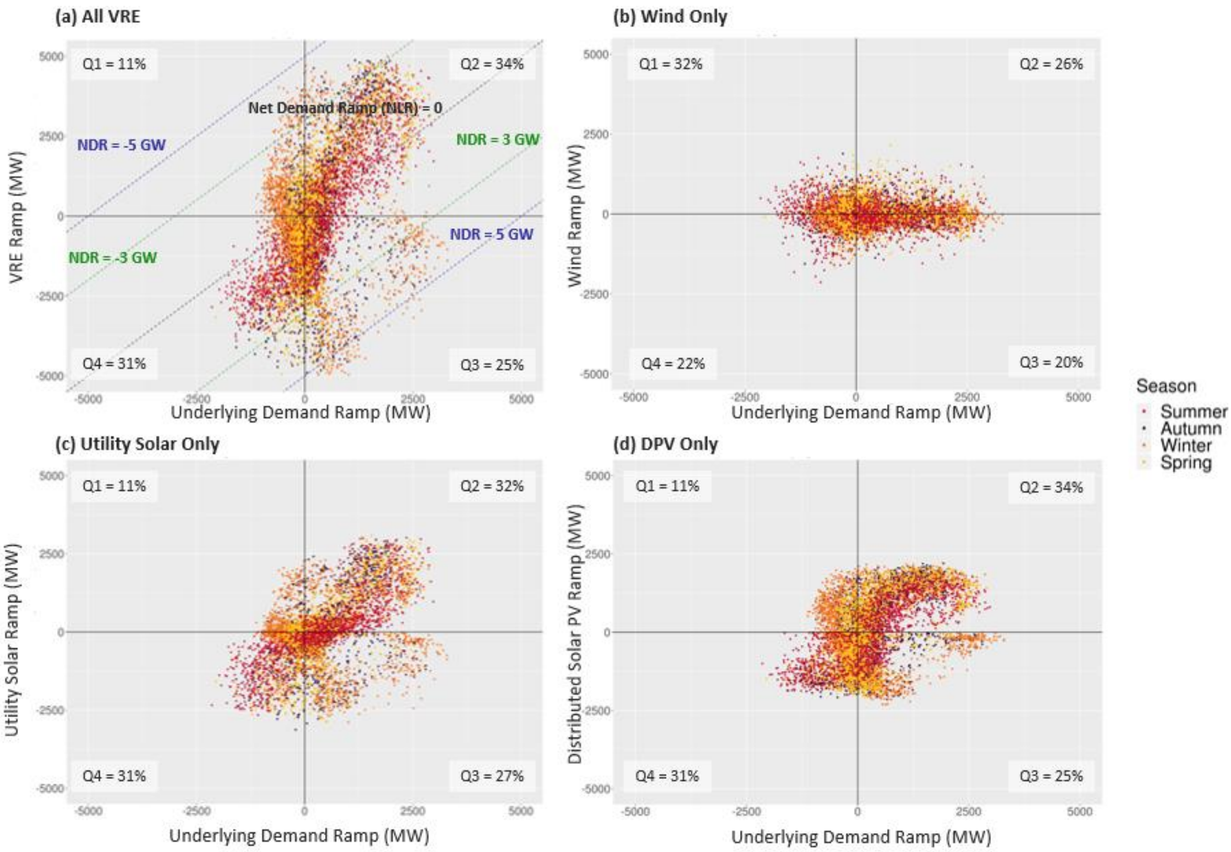
[34] Utility solar has 59% of points and DPV has 61% of points in Q2 and Q4.

solar and DPV spend the most hours moving in the same direction as underlying demand in autumn (utility solar = 73%; DPV = 76%) and the least amount of time in spring (utility solar = 40%; DPV = 42%).

- **Upward net demand ramps greater than 3 GW were mainly driven by an increase in underlying demand in 2018 exacerbated by a subsequent reduction in solar** – in all cases, utility solar and DPV ramped down over the same time period, making the net demand ramp larger. Wind was more varied, with ramp downs in wind observed in 33% net demand ramps greater than 3 GW.
- **The largest upward net demand ramps occur in the winter** (Panel (A), orange points) – this is mostly driven by utility solar and DPV ramping down as the sun sets, coinciding with evening underlying demand requirement. Figure 9 (Section C4.3.1) demonstrates the different net demand profiles between seasons and highlights the steepness of the net demand ramp to the evening peak in winter compared to other seasons.

Figure 14 presents the same information as Figure 9, but for a projected 2025 year.

Figure 14 Changes in 1-hour underlying demand and VRE in 2025, including drivers



Note: percentages values shown represent the proportion of points that fall within each quadrant.

Key observations from Figure 14 are:

- **VRE resources are projected to play a more significant role in influencing net demand ramps, compared to 2018** – while the distribution of underlying demand ramps across the width of the plots are projected to grow only marginally, the projected increase in magnitude of VRE ramps is evident by a dramatic increase in the height of the plot.
- Despite the change in distribution, the **patterns of VRE ramping with respect to demand are expected to remain consistent** with historical trends, shown by a similar percentage of points falling in each quadrant in 2018 and projected for 2025.

- As well as a projected growth in upward net demand ramps that are > 3 GW, **there is also a projected growth in large downward net demand ramps that are less than -3 GW projected for 2025**. These ramps are anticipated to be exclusively in morning hours during the solar ramp up. In 74% of these cases wind is also ramping up, increasing the size of the downward net demand ramp. This projection also highlights the **importance of downward flexibility in the system**.
- The **largest net demand ramps in 2025 are also projected to occur in winter,** driven by a coincident ramp down in utility solar and DPV and ramp up in underlying demand. The diurnal pattern exhibited by solar resources and underlying demand is largely predictable and so can be planned for by AEMO. However, consideration needs to be given to the magnitude of the entire ramp from the solar peak to the evening peak and the rate of change associated with that ramp.

C3.4.4 4-hour net demand ramps

Table 8 displays the statistics of 4-hour net load ramps (magnitude only) across the NEM. This table shows that the **magnitude of 4-hour net demand ramps is projected to increase significantly out to 2025**. Large 4-hour ramps are characteristic of the movement from the solar peak[35] to the evening peak[36], where the need for scheduled generation goes from its lowest to its highest, as it is required to replace the supply lost by solar power as the sun sets. This requires the scheduled fleet to have the capability to operate flexibility in response to this daily requirement[37].

Table 8 NEM 4-hour net demand ramp statistics

	Average	Maximum		99th Percentile	
	MW	Upward (MW)	Downward (MW)	Upward (MW)	Downward (MW)
2015	2,627	9,934	-6,449	8,188	-5,556
2016	2,619	10,163	-6,701	7,906	-5,582
2017	2,718	9,062	-8,600	7,920	-6,025
2018	2,772	9,758	-7,415	7,971	-5,961
2025	3,521	12,992	-11,517	10,903	-8,625

Figure 15 shows average net demand traces for winter months in the NEM[38]. The 2025 trace gives a view of potential average requirement on the scheduled fleet, if wind, utility solar, and DPV across the NEM are uncurtailed.

These curves best represent the average flexibility requirements on the scheduled fleet across years, and show how these requirements will change with changing grid conditions and higher penetrations of VRE:

- **Reduction in the midday trough** – as the penetration of utility solar and DPV increases, the midday trough becomes deeper[39]. This figure shows the net demand requirement (the energy required from conventional generators) in winter could reach as low as 11,728 MW on average by 2025. However, further analysis suggests that this minimum requirement could reach as low as 8,234 MW across the NEM (see case study below).

[35] The time in the middle of the day when penetration from utility solar and DPV is highest.

[36] Time in the evening when underlying demand is highest.

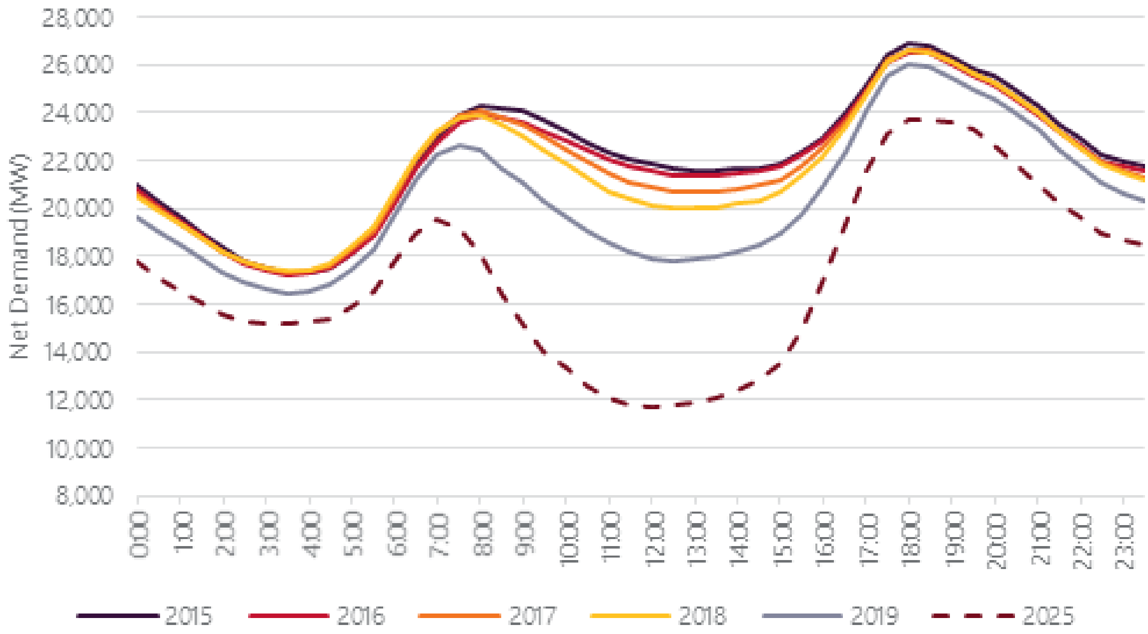
[37] See Section C5 for a discussion on system flexibility.

[38] Graphs for summer, autumn, and spring are available in the supplementary materials section.

[39] See Appendix A for a discussion on minimum demand and DPV.

- **Downward shift in the curve** – the general downward shift in the curve, outside daylight hours, can be attributed to the increase in generation from wind resources. As these curves represent an average, the shift down appears generally uniform, however the day-to-day variability of actual wind generation may deviate significantly.
- **Steeper ramping needs** – the reduction in the midday trough is far larger than the shift down in the evening peak, making the ramp from solar peak to evening peak larger and steeper. This effect is most pronounced in the winter profiles (Figure 9, Section C3.4.1). While spring profiles, on average, have a lower midday trough[40], the evening peak demand in winter is much higher than spring, making the average winter evening ramp more severe.

Figure 15 NEM average winter net demand curves



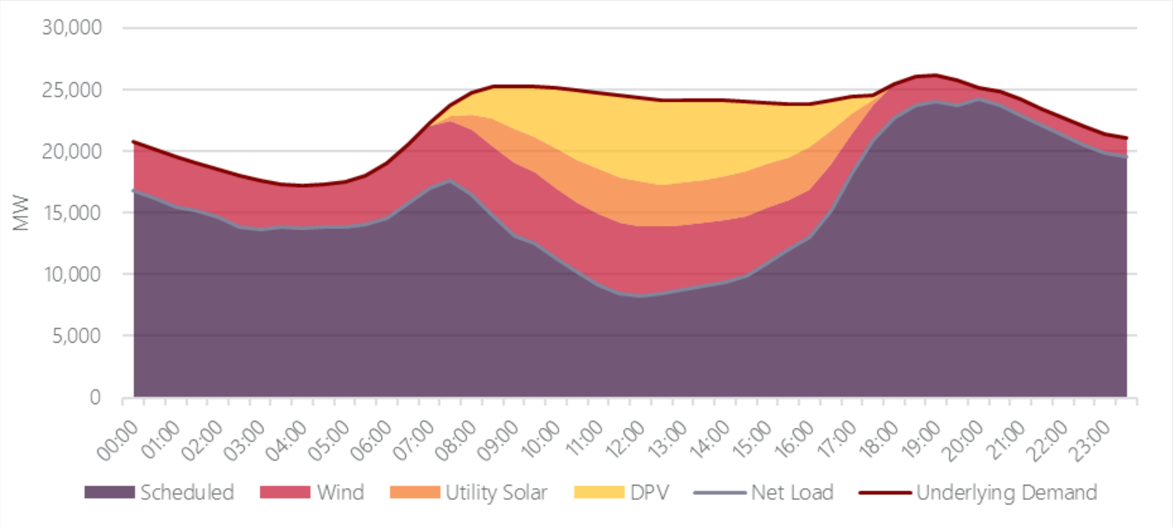
[40] See the supplementary materials section (Figure 25) for a seasonal comparison.

Case study | NEM | Largest movement from solar peak to evening peak

Figure 16 displays a representative winter weekday profile for the NEM that was projected for 2025. In constructing this graph, it was assumed that no wind, solar, or DPV have been curtailed.

The minimum net demand for the day is 8,234 MW at 12:00, at which time VRE is accounting for 66% of NEM underlying demand. The evening maximum net demand in this profile is 24,188 MW, occurring at 20:00. At this time VRE (wind only) accounts for only 4% of underlying demand. The total movement from the midday trough to the evening peak is 15,954 MW over 8 hours (between 12:00 and 20:00). However, the maximum 4-hour ramp is 13,794 MW between 14:30 to 18:30.

Figure 16 Net demand ramp in 2025



On this case study day in 2025, the requirement for low scheduled generation in the middle of the day and comparatively high need for scheduled generation in the evening is projected to be met by cycling of thermal generators (including coal, gas, and hydro).

Modelling (as described in Section C5) indicates the flexibility as described in Table 9 (below) was required by the scheduled fleet throughout this day This table shows that coal and hydro units were decommitted throughout the day to manage the increased supply provided by VRE. The 4-hour ramp between 15:00 and 19:00 required a combination of coal, gas, and faster starting hydro and peaking gas and liquid to come online to maintain the supply-demand balance.

Table 9 Number of conventional units online and generating throughout the day

Time	Coal	Gas	Peaking gas and liquids	Hydro
08:00	33	0	0	51
15:00	22	0	0	30
19:00	37	12	3	68

This case study provides an example of the requirement for the fleet to behave more flexibly as VRE penetrations grow and resultant net demand variability increases. While analysis in Section C5 shows that in many cases meeting large ramps in net demand is physically possible, whether it is a practical and prudent method to operate the system on a daily basis is worth considering.

C4. Uncertainty

This section explores AEMO's historic ramp forecast accuracy for 2018 and how this would translate if current forecasting approaches are carried forward into a future with increased variability from wind and solar. Large ramp events (defined by changes that are > 10%, > 20%, and > 30% of installed capacity) are explored, as they may have the most impact on the system and so are of most concern to AEMO[41].

This section focuses on 1-hour ramp windows for utility wind and solar forecasts, considering 1-hour ahead, 8-hour ahead, and 24-hour ahead lead times.

Key insights

- The level of accuracy and precision achievable even by best practice weather forecasts can lead to significant challenges in predicting VRE output and variability in the power system.
- Current forecasting models provide deterministic forecasts of expected future wind and solar output for individual farms aggregated across a region. The forecasting models are not probabilistic and do not explicitly account for the uncertainty of forecast conditions.
- Recent wind and solar output give a good indication of the level of future output (close to real time), but do not give a good indication of future variability.
- To reduce operational risk arising from the additional uncertainty in the system, sufficient flexibility is required within the system to deal with unexpected events. Advances in forecasting models and enhancements to operational tools and market mechanisms should be considered.

Uncertainty relates to the inability to perfectly predict future demand, supply, and grid conditions.

C4.1 Wind and solar forecasting in the NEM

AEMO is required to prepare a forecast of available capacity for semi-scheduled wind and solar generating units across the NEM[42]. These forecasts are inputs into dispatch, pre-dispatch, reliability assessment[43] and outage assessment. Currently, wind and solar energy forecasts are produced by the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS)[44,45].

The forecasting of VRE is more important than ever for the operation of the power system, as it is becoming a more influential component in determining resource availability across the NEM. Resource availability, including confidence in that availability estimate, in turn affects the ability of the system to maintain the

[41] The > 10% category also includes the > 20% and > 30% categories and the > 20% category also includes the > 30% category.

[42] In accordance with clause 3.7B of the NER.

[43] As part of the PD and ST PASA processes.

[44] Forecasts for DPV are omitted from this analysis. Forecasts for DPV are reflected in the demand forecast, as AEMO considers DPV as negative demand, rather than supply. Further, inaccuracies in the DPV forecasts are reflected as demand forecast error in AEMO systems. This section focuses on supply side forecast accuracy.

[45] Information on AEMO's AWEFS and ASEFS systems is at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting.

supply-demand balance. Outcomes of low resource availability or high uncertainty may include AEMO intervention in the market, including directions, instructions, or RERT (described further in Section C2.3.3).

Technological development and innovation have resulted in significant improvements in weather forecasting accuracy, particularly over the last 20 years, with advances in computing power, sensing equipment, and data processing. However, the level of accuracy and precision achievable by best practice weather forecasts can lead to significant challenges in managing VRE output and the power system.

AEMO's operational forecasting models provide deterministic forecasts of expected future wind and solar output for individual farms aggregated across a region (point forecasts). The forecasting models are not probabilistic and do not explicitly account for the uncertainty of forecast conditions. Currently, these point forecasts are statistically adjusted to create a distribution and the 50th percentile of the distribution is used in market processes (dispatch, scheduling, and reserve assessment)[46].

Producing accurate energy forecasts for wind and solar on high variability days, such as those characterised by changes in wind or cloud movements, is challenging over both short and longer forecasting lead times:

- **Energy forecast models over longer forecast lead times** (> 1 hour) rely on Global Numerical Weather Prediction (NWP) models. Their coarse spatial and temporal resolution present challenges to forecasting extreme weather-driven ramps, particularly when an event is affected by local climatology and complex terrain. These models tend to produce smoother profiles across a forecast horizon, however they do reliably incorporate broader synoptic-scale weather events and provide valuable guidance around larger-scale events, such as frontal wind changes.
- **Energy forecast models over shorter forecast lead times** (< 1 hour[47]) rely on a mixture of persistence forecasts and real-time meteorological and farm information (SCADA) to model output. While forecasts improve closer to real time as more up to date information is incorporated, the persistent component of these forecasts means they tend to lag actual real-time generation. This creates challenges, particularly on highly variable days, as the point forecast may vary significantly from one period to the next. While these models show additional variability over the outlook horizon, they may mis-time this variability, introducing additional uncertainty around the timing of events.

Challenges in forecasting wind and solar

AEMO's experience is that the following conditions are common causes of weather inaccuracy:

- **Day ahead models** – weather systems developing and changing faster or slower than model prediction as a result of:
  - Long lead times ingesting weather observations used by global weather models (used as the basis for all weather forecasts), resulting in the model not reflecting reality. This is particularly evident when weather systems are rapidly changing.
  - Long periods between model re-runs of the global weather models (in most cases, they are only re-run every 12 hours).
  - Local phenomena not modelled in global weather models including:
    - Complex terrain, such as intricate shorelines, which may create local sea breezes, or ridgelines which may create strong diurnal winds.
    - Local precipitation, leading to atmospheric mixing which creates local convective winds.
- **Models closer to real time** – typical difficulties in the conversion of the weather-dependent fuel source (wind and sunlight) to energy for VRE assets include:
  - Lack of precision in position and timing of cloud movements across generation assets. This is particularly difficult when there is cloud that is intermittent and scudding (moving quickly and without stopping in a straight line).
  - Unpredictable wind changes, as a result of wind eddies and temperature differentials in the atmosphere.
  - Limited industry use of on-site sensing equipment to provide lead indicators into forecast models. (See Section C6 for a description on participant self-forecasting methods being used to predict generation output for short lead times.)

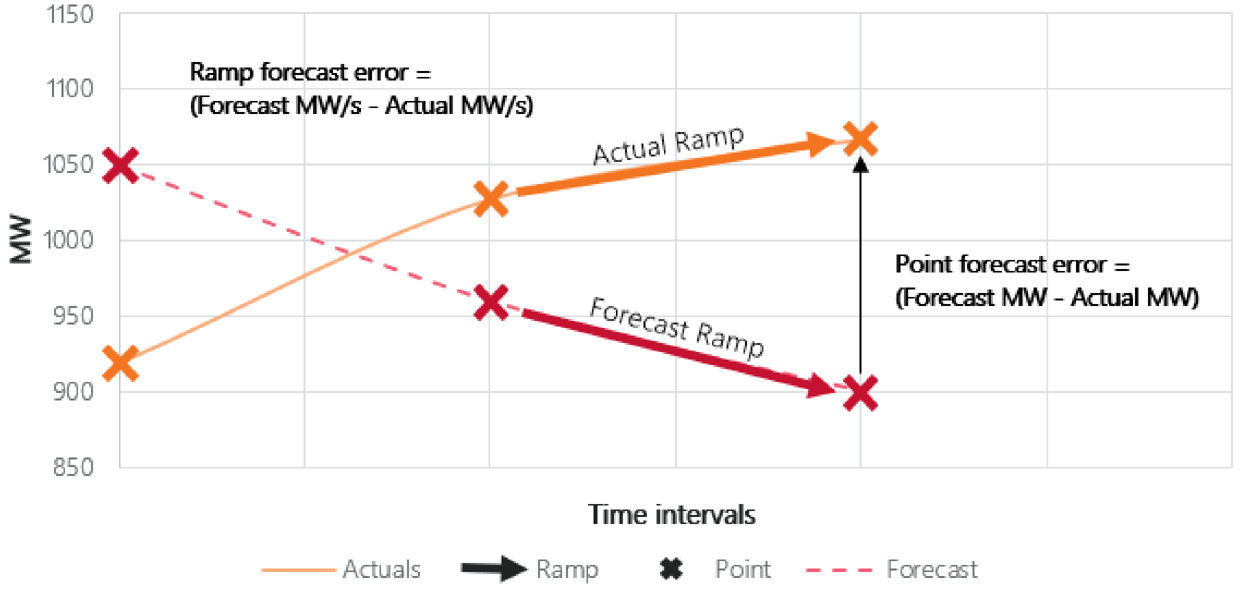
[46] The 10th and 90th percentile of the distribution is used to inform lower and upper bounds and manage operational conditions.

[47] This includes Dispatch and 5-minute Pre-Dispatch timeframes.

C4.2 Forecast accuracy

This section provides a discussion on the *point* forecast accuracy of AEMO forecasts, as well as a view on the *ramp* forecast accuracy and the merit of accounting for uncertainty in wind and solar forecasts. The key differences between point forecast accuracy and ramp forecast accuracy are presented in Figure 17 and discussed in detail below.

Figure 17 Comparison of *point* forecast accuracy and *ramp* forecast accuracy



Point forecast accuracy

Table 10 presents the *point* forecast accuracy for aggregate wind and utility solar in the NEM. *Point* forecast accuracy provides a reasonable view of the ability of AEMO's deterministic forecasts to predict the **magnitude** of wind and solar generation at a future point. The ability of the model to predict the **timing of fluctuations** will also influence forecast accuracy. For example, if an upward ramp occurs earlier than was forecast, there may be some underestimation error during the time delay between actual and forecast values.

Point forecast accuracy is the point difference between a forecast value and actual value for a single point in time.

Point forecast accuracy is what AEMO uses to assess the performance of its forecasting models.

- ***Point* forecast accuracy improves as the forecast point in time approaches real time (forecast lead time reduces)**. For both solar forecasts and wind forecasts, the root mean square error (RMSE) decreases as the forecast lead time reduces, meaning the spread forecast values converge towards the actual values the closer to real time the forecast is taken. For example, in 2018 the aggregate NEM forecast for wind had an RMSE of 229.54 for the 24-hour ahead forecast; the RMSE reduced to 36.58 by the 5-minute ahead forecast. Similarly, the maximum over-forecast value (more wind was forecast than was actually available in real time) for wind in the 24-hour ahead model is 1,018 MW, which reduces to 335 MW in the 5-minute ahead model. This trend is consistent for wind and solar across all regions.
- **When normalised for installed capacity, wind *point* forecasts are more accurate than solar *point* forecasts for lead times up to 24 hours ahead and *vice versa* when expressed in absolute terms.** The RMSE normalised for online installed capacity is larger for solar than for wind at every forecast horizon in Table 10. There are two factors that, in combination, may contribute to this difference:

- **Installed capacity of solar versus wind** – as installed capacity of wind or solar increases in a region, the RMSE of forecast and actual output expressed as a percentage of capacity tends to reduce, while RMSE expressed in absolute terms tends to increase. The installed capacity of solar was less than wind across the NEM in 2018. As installed capacity increases over a geographically diverse fleet, there is a higher probability that variability from individual farms will offset each other, resulting in a smoother and more predictable output, when represented on a capacity basis. However, as the amount of installed capacity increases there is more scope for larger underestimation and overestimation deviations.
- **Impacts of scudding intermittent cloud on solar forecast accuracy** – solar farms are typically installed in a much smaller geographic area relative to a wind farm of similar capacity. Although both wind and solar farms are subject to random weather changes (such as a cloud passing over a solar farm, or a wind gust affecting a wind farm), the impact of a cloud passing over a solar farm is disproportionately larger than a wind gust affecting a wind farm, due to the cloud typically affecting the majority of the solar farm compared to the wind gust typically affecting a few turbines. This results in the potential for less volatility period-to-period for a wind farm relative to a solar farm, which leads to a reduction in larger forecast errors.

Table 10 NEM *point* forecast accuracy by fuel type in 2018[A,B]

Forecast lead time (minutes/ hours ahead)	Observations (n)	Maximum underestimation (MW)	Maximum overestimation (MW)	RMSE	RMSE/ Capacity C
Solar[D]					
5 mins ahead	59,812	-166	145	**18.33**	**4.53**
15 mins ahead	59,812	-185	182	**23.60**	**5.81**
1 hours ahead	9,978	-134	163	**26.00**	**5.77**
8 hours ahead	9,978	-129	238	**28.95**	**6.31**
24 hours ahead	9,978	-154	220	**30.48**	**6.66**
Wind					
5 mins ahead	105,116	-351	335	**36.58**	**0.80**
15 mins ahead	105,116	-522	620	**62.56**	**1.37**
1 hours ahead	17,520	-764	669	**121.7**	**2.67**
8 hours ahead	17,520	-1,178	859	**199.5**	**4.40**
24 hours ahead	17,520	-1,347	1,018	**229.54**	**5.06**

A. See the supplementary materials section for an overview of statistical concepts, including RMSE.
B. Forecast values in this table are taken from AEMO's 5-minute Pre-Dispatch process for 5-minutes and 15-minutes, and from AEMO's Pre-Dispatch process for 1-hour, 8-hours, and 24-hours ahead. The number of observations for 5-minute and 15-minute ahead forecasts are higher due to the more frequent update cycle of the 5-minute Pre-Dispatch model compared to the Pre-Dispatch model.
C. RMSE/Capacity is calculated as the RMSE of forecast and realised values as a percentage of online installed capacity.
D. Values provided are for utility solar farms only. Only daylight hours are considered.

Ramp forecast accuracy

Table 11 presents the *ramp* forecast accuracy for aggregate wind and utility solar in the NEM over a 1-hour ramp window. Ramp forecast accuracy:

Ramp forecast accuracy is the difference between a forecast change and an actual change between two points.

For example, if an upward ramp of 50 MW is forecast between 08:30 and 09:30 and the actual ramp was 200 MW over the same period, then the ramp forecast error would be -150 MW (150 MW under forecast).

- Provides a view of the ability of AEMO's deterministic forecasts to predict the **magnitude, timing** and **rate of change** of a ramp in wind and solar generation at a future point. *Ramp* forecast accuracy is a more sensitive measure than *point* forecast accuracy, as it includes a rate of change component in its measurement.
- **Does not improve as the forecast lead time approaches real time for 1-hour ramps**. As shown in Table 11, there are no significant changes to maximum under- or over-forecast error, RMSE or RMSE normalised for online installed capacity as the forecast horizon approaches real time. This trend is consistent across all NEM regions.

This finding is in contrast to the improvements seen for point forecast accuracy. As the forecast lead time approaches real time, AEMO models include a greater weighting on persistence (that is a lagged component to represent output that has just occurred). The findings indicate that **recent wind and solar output gives a good indication of the level of future output (close to real time) but does not give a good indication of future variability**.

Table 11 Solar and wind ramp forecasts in the NEM, 1-hour ramp window in 2018[A]

Ramp size (% online installed capacity)	Forecast lead time (hours ahead)	Observations (n)[B]	Maximum Underestimation (MW)	Maximum Overestimation (MW)	RMSE[C]	RMSE/ Capacity[D]
Solar						
All	1 Hour	9,244	-134	163	26.71	5.95
	8 Hours	9,244	-171	156	23.58	5.48
	24 Hours	9,244	-144	145	23.96	5.52
> 10%	1 Hour	5,558	-134	163	29.66	6.78
	8 Hours	5,412	-171	156	26.55	6.41
	24 Hours	5,429	-144	145	27.07	6.47
> 20%	1 Hour	3,069	-134	156	27.91	6.67
	8 Hours	2,902	-171	156	26.23	6.47
	24 Hours	2,921	-134	145	26.65	6.53
> 30%	1 Hour	1,232	-134	150	26.85	6.53
	8 Hours	1,100	-113	142	25.51	6.62
	24 Hours	1,083	-129	136	25.90	6.72
Wind[E]						
All	1 Hour	17,520	-764	669	120.46	2.65
	8 Hours	17,520	-757	857	115.05	2.53
	24 Hours	17,520	-796	760	118.86	2.61
> 10%	1 Hour	111	-718	669	392.68	8.77

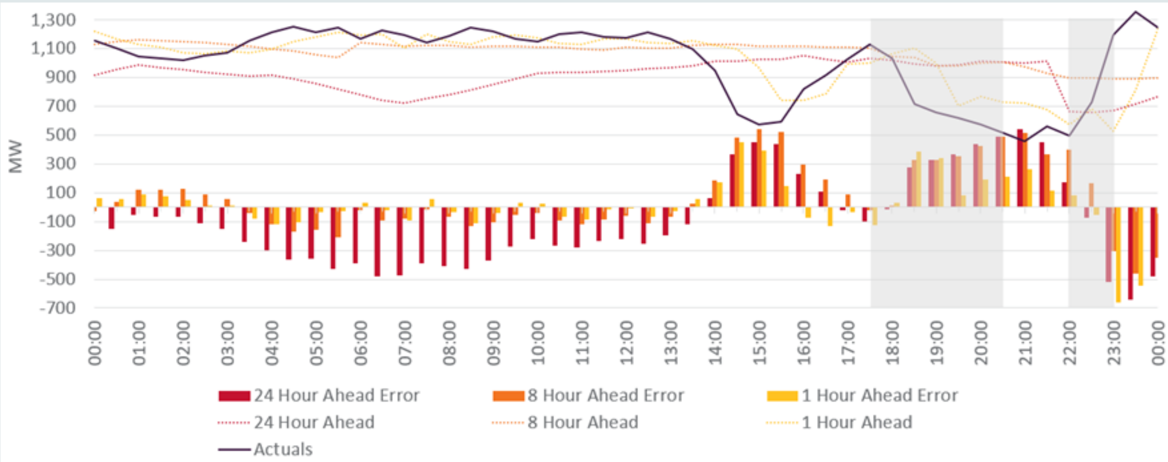
Ramp size (% online installed capacity)	Forecast lead time (hours ahead)	Observations (n)[B]	Maximum Underestimation (MW)	Maximum Overestimation (MW)	RMSE[C]	RMSE/ Capacity[D]
	8 Hours	112	-757	857	371.65	8.29
	24 Hours	111	-796	760	391.69	8.76

A. Values in this table are based on forecasts from AEMO's pre-dispatch system.
B. Number of observations may differ between wind and solar due to data cleaning.
C. See supplementary materials section for a description of root mean squared error (RMSE).
D. RMSE/Capacity values are calculated as RMSE of forecast and realised ramp as % of installed capacity.
E. There were no hourly wind ramps observed above 10% of capacity in 2018.

Case study | South Australia | Monday, 18 December 2017

This is a continuation of the case study at the end of Section C3.2.3. Figure 18 shows the rolling 24-hour, 8-hour, and 1-hour ahead South Australia wind generation forecasts (traces) and errors (bars) against the actual wind generation for the region.

Figure 18 Wind forecasts v actuals



Tables 12 and 13 show the difference between the point forecast accuracy and ramp forecast accuracy for the downward and upward ramps, highlighted in Figure 18.

Table 12 Forecast accuracy for downward ramp between 17:30 and 20:30

	Point forecast accuracy (at 20:30)	Ramp forecast accuracy (17:30 – 20:30)
1 HA	212 MW	-
8 HA	489 MW	523 MW
24 HA	493 MW	568 MW

Table 13 Forecast accuracy for upward ramp between 22:00 and 23:00

	Point forecast accuracy (at 23:00)	Ramp forecast accuracy (22:00 – 23:00)
1 HA	-663 MW	-663 MW
8 HA	-303 MW	-699 MW
24 HA	-521 MW	-689 MW

The actual downward ramp between 17:30 and 20:30 was -612 MW over three hours. The 8-hour ahead *point* forecast for 20:30 was 1,006 MW and the actual generation for 20:30 was 517 MW, meaning there was an over-forecast generation variance of 489 MW.

For the 8-hour ahead *ramp* between 17:30 and 20:30, the forecast was for a downward ramp of -88 MW and the actual ramp was -612 MW, meaning the change over the 3-hour period was overestimated by 523 MW.

The actual upward ramp between 22:00 and 23:00 was 701 MW over one hour. The 8-hour ahead *point* forecast for 23:00 was 891 MW and the actual generation was 1,195 MW, meaning there was an underestimation variance of -303 MW. The 8-hour ahead ramp forecast between 22:00 and 23:00 was 2 MW and the actual ramp over that period was 701 MW, so the ramp was underestimated by -699 MW.

Forecast variances of the magnitude observed on this day present significant challenges to real-time operation of the power system, as they can require high levels of reserves, and impact market price forecasting and outcomes.

The event was characterised by a wind change due to a large low-pressure system that moved east across the state throughout the day, with the general wind direction shifting from north-westerly to south-westerly (see case study in Section C3.2.3 for a description of weather on the day). During the event, the local effects of the pre-frontal trough and a large band of precipitation wasn't well resolved by the NWP.

Forecasting this type of wind event is a significant challenge. Modelling of wind due to localised precipitation is a well-known challenge for NWPs. Due to the difficulties in forecasting such events through global NWP, there was a significant increase in forecast inaccuracies during the ramping periods. Notably, the 24-hour and 8-hour forecast showed minimal predictions of the ramping event, and the 1-hour forecasts lagged actual generation throughout the day.

Despite the large magnitude of the ramp and associated forecast error, the event on 18 December 2017 did not result in the loss of load or deviation outside the defined technical limits, which are the goals of system reliability and security.

Key contributors to this include:

- Underlying load was decreasing, following the evening peak. This offset the amount of ramping coverage needed from interconnection and the scheduled fleet.
- The Bureau of Meteorology (BOM) had issued a severe weather warning. AEMO assessed that the weather conditions added risk to the power system in South Australia. To manage this risk, AEMO's control room was on alert for variability in wind generation in South Australia and limited the flow on the Heywood interconnector from Victoria to South Australia.
- There was sufficient headroom on the Heywood interconnector to provide coverage for the decrease in local wind generation, in addition to some support from local online gas generation. No directions were issued by AEMO during this ramping event.

C4.3 Classifying ramping events

As shown in Section C3.2, from a *ramp forecast accuracy* perspective, future variability is not captured effectively. Another way to assess the performance of forecasting models when predicting ramps is to frame the forecast results as a classification problem. This classification approach is a theoretical look at whether the relationship between a forecast ramp and realised ramp is captured in any capacity for extreme ramp events.

Table 14 and Table 15 describe the forecast performance for 1-hour ramps in utility solar and wind, respectively, by classifying the type and prevalence of forecast errors[48]. For example, for a ramp that is forecast to be >10% of online installed capacity:

- If the realised ramp over the same time period is also > 10% of online installed capacity, then the ramp is **forecast and realised**.
- If the realised ramp is < 10% of online installed capacity, then it is classified as **forecast and unrealised**[49].

Alternatively, if there is an actual ramp that is > 10% of installed capacity:

- If the forecast ramp over the same time period is also > 10% of online installed capacity, then the ramp is **forecast and realised**.
- If the forecast ramp is < 10% of online installed capacity, then it is classified as **unforecast and realised**.

The tables also report on recall and precision. **Recall** is the ability of the model to forecast only relevant ramps. That is, given that a ramp is forecast, the probability that the forecast is correct. **Precision** is the ability of the model to capture all ramps that occur. That is, given a ramp occurred, the probability that it was

48 For NEM 1-hour wind ramps, only 4 events were identified with a magnitude > 20%.

49 There is no sensitivity threshold applied to this analysis. This means that if a ramp is forecast to be > 10% of online installed capacity and a ramp of 9.98% is realised, this would be classified as forecast and unrealised.

forecast. A balance between recall and precision is desirable, as this indicates that the model reliably identifies ramping behaviour, without overstating the amount of variability in the system.

Table 14 shows forecast precision for utility solar ramps across the NEM and provides a comparison between forecast ramps in the middle of the day and at sunrise and sunset hours:

- **The majority of ramps >10% of installed capacity of solar in the NEM occur at sunrise and sunset hours**. This is supported as there are more observations recorded in Panel (A) compared to Panel (B).
- **Uncertainty is reduced for solar forecasts at sunrise and sunset hours**. For an 8-hour ahead forecast for a 1-hour ramp that is > 10% of solar capacity, recall and precision are 89.75% and 96.51% respectively for sunrise and sunset hours; however, they drop to 30.28% and 55.49% respectively for midday hours. This drop in accuracy indicates that the forecasting model is less effective at forecasting cloud transients in the middle of the day, compared to predicting changes solar output due to sunrise and sunset.
- **There is some evidence to suggest that the occurrence of ramps is generally predicted, however the timing of these ramp events is not**. This is supported by the fact that the number of events that were forecast but did not occur was similar to the number of events that occurred but were not forecast[50].

Table 14 Forecast precision for 1-hour utility solar ramp in the NEM in 2018

Ramp size (% online installed capacity)	Forecast horizon	Observations	Forecast & realised	Forecast & unrealised	Not forecast & realised	Precision (%)	Recall (%)
Panel A: Sunrise and sunset ramps[A]							
> 10%	1 hour	4,615	4,067	397	151	**91.11**	**96.42**
	8 hours	4,683	4,071	465	147	**89.75**	**96.51**
	24 hours	4,697	4,066	479	152	**89.46**	**96.40**
> 20%	1 hour	2,963	2,170	592	201	**78.57**	**91.52**
	8 hours	2,835	2,038	464	333	**81.45**	**85.96**
	24 hours	2,853	2,057	482	314	**81.02**	**86.76**
> 30%	1 hour	1,221	766	319	136	**70.60**	**84.92**
	8 hours	1,090	631	188	271	**77.05**	**69.69**
	24 hours	1,075	631	173	271	**78.48**	**69.69**
Panel B: Midday ramps[B,C]							
> 10%	1 hour	943	257	342	344	**42.90**	**42.76**
	8 hours	747	182	146	419	**55.49**	**30.28**
	24 hours	732	162	131	439	**55.29**	**26.96**
> 20%	1 hour	106	10	39	57	**20.41**	**14.93**
	8 hours	67	0	0	67	**0**	**0**
	24 hours	68	0	1	67	**0**	**0**
> 30%	1 hour	11	0	3	8	**0**	**0**

[50] This evidence is conditional on the time of day. Table 10 shows that this trend is generally consistent over sunrise and sunset hours for all forecast lead times and for midday hours for 1-hour lead times. However, midday ramps over 8-hour and 24-hour lead times do not generally support this insight.

Ramp size (% online installed capacity)	Forecast horizon	Observations	Forecast & realised	Forecast & unrealised	Not forecast & realised	Precision (%)	Recall (%)
	8 hours	8	0	0	8	**0**	**0**
	24 hours	8	0	0	8	**0**	**0**

A. Includes 1-hour ramps that occurred between 5:00 to 10:00 and 15:00 to 20:00.
B. Includes 1-hour ramps that occurred between 10:00 to 15:00.
C. No midday solar ramps exceeded 40%, as such this category is omitted from the table.

Table 15 shows the forecast precision for 1-hour wind ramps in South Australia. Statistics for South Australia are included instead of NEM-level results, as there were no wind ramps above 20% of installed capacity recorded in 2018 for the NEM to provide a comparison between the precision and recall of different sized ramps.

There is a higher degree of uncertainty when forecasting hourly wind ramps than hourly solar ramps. This is supported by a lower precision and recall for forecasts of wind ramps compared to solar ramps across 1-hour, 8-hour and 24-hour lead time, and is consistent across the NEM and regions with both wind and solar generation capacity in 2018.

Table 15 Forecast precision for 1-hour wind ramp in South Australia in 2018

Ramp size (% online installed capacity)	Forecast Horizon	Observations	Forecast & Realised	Forecast & Unrealised	Not forecast & Realised	Precision (%)	Recall (%)
> 10%	1 hour	1,286	71	114	1,101	**38.38**	**6.06**
	8 hours	1,289	71	117	1,101	**37.77**	**6.06**
	24 hours	1,263	66	91	1,106	**42.04**	**5.63**
> 20%	1 hour	71	0	0	71	**0**	**0**
	8 hours	72	0	1	71	**0**	**0**
	24 hours	71	0	0	71	**0**	**0**
> 30%	1 hour	4	0	0	4	**0**	**0**
	8 hours	4	0	0	4	**0**	**0**
	24 hours	4	0	0	4	**0**	**0**

C4.4 Summary

Variable events, such as changes in wind or cloud movements, are challenging to forecast accurately over both short and longer forecasting horizons. Technological development and innovation have resulted in significant improvements in weather forecast accuracy, however the level of accuracy and precision achievable by best practice weather forecasts can still lead to significant challenges in predicting VRE output and variability in the power system.

The magnitude and frequency of net demand ramps in the NEM is increasing. The largest historical 1-hour ramp in VRE was 4.2 GW, but by 2025 is projected to be as large as 6.1 GW. By 2025, net demand ramps are expected to be driven primarily by changes in VRE (details in Section C3). These changes, coupled with challenges in forecasting wind and solar ramping events, pose an increased risk to the system.

While there is an opportunity for efficient markets to appropriately price additional variability and uncertainty in the market, AEMO also needs to monitor and manage potential security risks to the system.

This means there is a need for AEMO to improve the performance of weather forecasting and power forecasting models or develop new dedicated operational tools to appropriately manage uncertainty under variable or extreme weather conditions.

Flexible resources are also needed, to cover the residual uncertainty that cannot be addressed by forecasting improvements and variability that is innate to wind and solar resources.

C5. System flexibility

This section assesses the capability of the NEM, under current regulatory frameworks, to accommodate additional variability and uncertainty from VRE resources, under the Draft 2020 ISP Central scenario expansion plan in 2025. It covers:

- The need for system flexibility and key changes out to 2025.
- A regional analysis of system flexibility across 30-minute, 1-hour and 4-hour windows.

Key insights

- 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. System security becomes more challenging to manage where the demand and supply for flexibility is tight. This analysis suggests that by 2025 flexibility will be tightest in South Australia and Queensland.
- 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.
- The drivers behind the supply of flexibility are specific to the ramping window, region, market behaviour, and other operational or system events. Consideration needs to be given to how the requirements for system flexibility will change over time and the adequacy of market frameworks to guarantee efficient outcomes.
- In the absence of enhanced operational tools and regulatory frameworks, VRE curtailment and/or market intervention may be required to maintain adequate system flexibility across all time frames.

System flexibility is the capability of the system to respond to expected and unexpected changes in net demand over all necessary timeframes.

C5.1 Background

As the penetration of VRE increases, the system needs to operate more **flexibly** to accommodate increases in variability and uncertainty. Many units have had to operate more flexibly than their intended design, with new territory being explored across the NEM around the physical and financial ways that units and portfolios are managed. As the system is pushed closer to its limits, management of the risk associated with variability and uncertainty becomes increasingly complex, with generators required to:

- React quickly to meet expected and any unexpected change in supply and demand.
- Start up with short notice.
- Sustain faster ramp rates[51] over longer durations.
- Provide more cycling throughout the day.

[51] In this section, “ramp rates” refer to a plant’s capability to quickly change output given resource adequacy. This differs to how ramp rates have been described previously in this report, where a ramp for a generating plant referred to a change in output due to a change in resource availability (that is a change which must be addressed by another source, namely the scheduled fleet and interconnection).

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.

Sources of flexibility

Sources of flexibility in the NEM include:

- **Conventional generation** – the flexibility of a generator is the extent to which its output can be adjusted or committed in or out of service, including the speed of response to start up and shut down, rate of ramping, and whether it can operate in the full range of capability, or has restrictions (such as minimum generation requirements, or other limitations).
  - The most flexible conventional generation types are often hydro, gas turbines, and other liquid fuel generators, as they can ramp their output up and down relatively quickly and can have short start up times. However, ultimately unit flexibility is a product of its design and the economic circumstances around its dispatch.
  - Coal-fired generation is typically considered relatively inflexible. These units generally have long start up times, high minimum operating levels, and expensive start-up and shut-down costs (making it uneconomical to switch the unit on and off frequently). However, above their minimum operating levels, coal units have a wide operating range and provide significant contingency responses. Some coal units are increasing their flexibility through plant upgrades, such as allowing lower minimum operating levels and more frequent cycling of units. These approaches, however, may increase the wear and tear on the generating equipment, which may result in a rise in outage rates, repairs, maintenance, and depreciation of the unit.
- **Storage** can participate by increasing demand (load) or increasing supply (generation). It can decrease production or increase its load during periods of surplus generation, such as in high VRE periods. It can then increase production in periods where VRE is lower. Having a diverse range of technical characteristics across the storage fleet allows management of variability over different timescales, for example pumped hydro and battery storage.
  - **Pumped hydro** has the capability to quickly produce or demand large amounts of energy over a longer duration, although there are limitations to how quickly it can switch between these modes. New variable speed drive pumped hydro projects, such as three of Snowy 2's six units, are able to provide this flexibility almost instantaneously.
  - **Batteries** have fast response times and can cycle from charge to discharge much quicker than pumped hydro, however, the units currently installed in the NEM have a much shorter duration for which they can run. This is important, as having a diverse range of technical characteristics across the storage fleet allows management of variability over different timescales. Battery storage is also a scalable technology that can be readily co-located with VRE resources in a hybrid facility to firm VRE output or as a stand-alone installation.
- **Interconnection** improves the sharing of flexibility between adjacent regions. It increases the diversity of generation and supply across a system, which effectively smooths out total VRE generation and net demand. Headroom on interconnectors is limited by the available capacity from all generators in the adjacent region and the interconnectors that can import energy to that region, subject to their ramp rate limits and any constraints imposed on the interconnector flow.
- **Demand response** means the ability for end-users to reduce energy usage in response to a price signal or other incentive. Examples include control of flexible loads (such as pool pumps), distributed storage to flatten evening peaks, and "pre-cooling" that could be used to cool a residence on a hot day, so less cooling is required later in the day at the time of peak demand. One of the challenges in utilising demand response is the difficulty issuing wholesale price signals to these loads to incentivise desired behaviour.

Flexibility from VRE

Wind and solar resources have high ramp rates, short start-up times, and low minimum generating levels, subject to resource availability. However, for flexibility to be useful in system operations, flexibility must be able to be scheduled in the right direction at the right time.

Currently, dispatchability over the VRE fleet in the NEM is varied, from semi-scheduled wind and solar farms being included in scheduling and dispatch (but only constrained under some conditions), to non-scheduled wind and solar and DPV that are accommodated by the system, rather than controlled.

Curtailment of renewables can contribute to flexibility in three key areas:

- As variability and uncertainty that arises from an increased penetration of VRE is contributing to a flexibility shortage, greater control or curtailment of these resources at certain times is likely to lead to a **smaller magnitude of ramp to be covered**.
- When system supply exceeds demand, or there is congestion in the transmission system, **downward flexibility** can be provided by curtailing semi-scheduled wind and solar (that is utilising footroom on VRE generators). Controllability across a greater share of the VRE fleet would provide scope for a greater response to potential over-supply or congestion[52].
- **Upward flexibility** may also be provided by VRE through pre-curtailment (or scheduling below the maximum available energy production) to create headroom[53].

As variability and uncertainty that arises from an increased penetration of VRE is contributing to a flexibility shortage, greater control or curtailment of these resources is likely to lead to a smaller magnitude of ramp to be covered.

Incentives to reduce spilt energy during curtailment may also promote investment in complementary flexible technologies for VRE.

Flexibility from system strength requirements

Currently in the NEM, some system flexibility is provided as a by-product of meeting the system strength requirements, for example in South Australia[54,55]. To meet these requirements, AEMO currently determines minimum conventional generator combinations. This requirement for a minimum number of large synchronous units online improves the flexibility of the generation fleet in that region, by bringing on additional generation at low loading, which has the consequence of increasing the available ramp headroom of the system (subject to ramp rate limits on these plants). However, it may be at the cost of displacing other generation (mainly wind and solar).

The direction of units to stay online outside of market dispatch increases flexibility as a by-product. Over time, system infrastructure may develop, including network augmentation and installation of equipment, such as synchronous condensers (syncons), which improve system strength, but don't provide system flexibility.

Changes over time

Changes in the composition of the fleet projected to 2025 may present challenges to utilising existing flexibility in the NEM in real-time operation.

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[52] Recommendation 3.4 in the RIS Stage 1 report highlights the need to collaborate with industry to mandate minimum device level requirements to enable emergency curtailment for new DPV installations. For a discussion of curtailability of the DPV fleet, see Chapter 3 of the RIS Stage 1 report and Appendix A.

[53] For a discussion on flexible solar plant operation, see Energy and Environmental Economics, Inc. (2018), Investigating the Economic Value of Flexible Solar Power Plant Operation, at https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

[54] See the system strength requirements and fault level shortfalls report for further information on system strength requirements methodology at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[55] See the transfer limit advice for further information on the requirements of system strength in South Australia an Victoria, including minimum unit combinations, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

Figure 19 Changes in fleet and interconnector composition, 2019 to 2025 Draft 2020 ISP Central scenario[A]

A. Based on the Draft 2020 ISP Central scenario build to 2025

Key changes that will affect flexibility are highlighted below and presented in Figure 19:

- **Generation retirements** – the conventional fleet has traditionally been a significant source of managing ramps. As the fleet ages and units reduce operation or retire, the residual flexibility available from conventional sources diminishes. The announced retirements to 2025, shown in Figure 19, include Liddell (2,000 MW coal in New South Wales), Torrens Island A (480 MW gas in South Australia), and Osborne (180 MW gas in South Australia)[56].
- **Displacement of online conventional generation** – during periods of high VRE penetration, some conventional generation will not be required to meet demand, and so may be not be dispatched. Once offline, the start-up and synchronising times of conventional generation may range from under 30 minutes for fast start plant[57] to days if a unit has been out of service for a prolonged period ('cold' start). The flexibility that can be provided from online conventional units is far superior to when they are offline.
- **Strengthening interconnection between regions** – the Draft 2020 ISP highlights several interconnection upgrades as priority Group 1 projects. These projects will improve sharing of flexibility between adjacent regions. Priority grid projects that are reflected in Figure 19 include EnergyConnect (New South Wales – South Australia interconnector) [58], VNI Minor (upgrade to Victoria – New South Wales interconnector), and QNI minor (upgrade to New South Wales – Queensland interconnector). Although these projects will increase flexibility, they may also lead to a change in market dynamics, which in turn may affect the availability of existing flexible resources.
- **Participant learning** – with larger penetrations of VRE increasing the need for flexibility, many participants are entering new territory in the way that they operate their plant and portfolios, meeting new engineering, financial and strategic challenges during a time of transition and uncertainty. As participants gain more experience operating amongst changing market dynamics, new behaviours may emerge which could influence the flexibility of the system. Two-shifting of coal units[59] and pre-curtailment of

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[56] A full list of generating unit expected closure dates is at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/nov-2019/generating-unit-expected-closure-year-08-november-2019.xlsb?la=en&hash=A0D22FFAA4C71A16404791EC813B48C8.

[57] A fast start unit is a unit that can synchronise and reach its minimum loading within 30 minutes, and can synchronise, reach minimum loading, and shut down in less than 60 minutes. It must register with AEMO as a fast start unit to participate in the NEM as a fast start unit but can submit offers as a fast start or slow start unit. More information is at https://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf.

[58] In addition, this project will increase the Heywood interconnector to 650 MW in both directions.

[59] See https://www.originenergy.com.au/blog/power-station-trial-aims-to-reduce-reliance-on-coal/.

renewables[60] are both examples of new behaviours which increase flexibility and are emerging out of the current change in market dynamics in the NEM.

Case study | South Australia | Flexible plant ramping

On Saturday, 12 October 2019 the underlying demand in South Australia was being met by very different combinations of technologies throughout the day.

High levels of wind and solar in the morning and middle of the day meant that combined generation from VRE was higher than from scheduled generation (including interconnection):

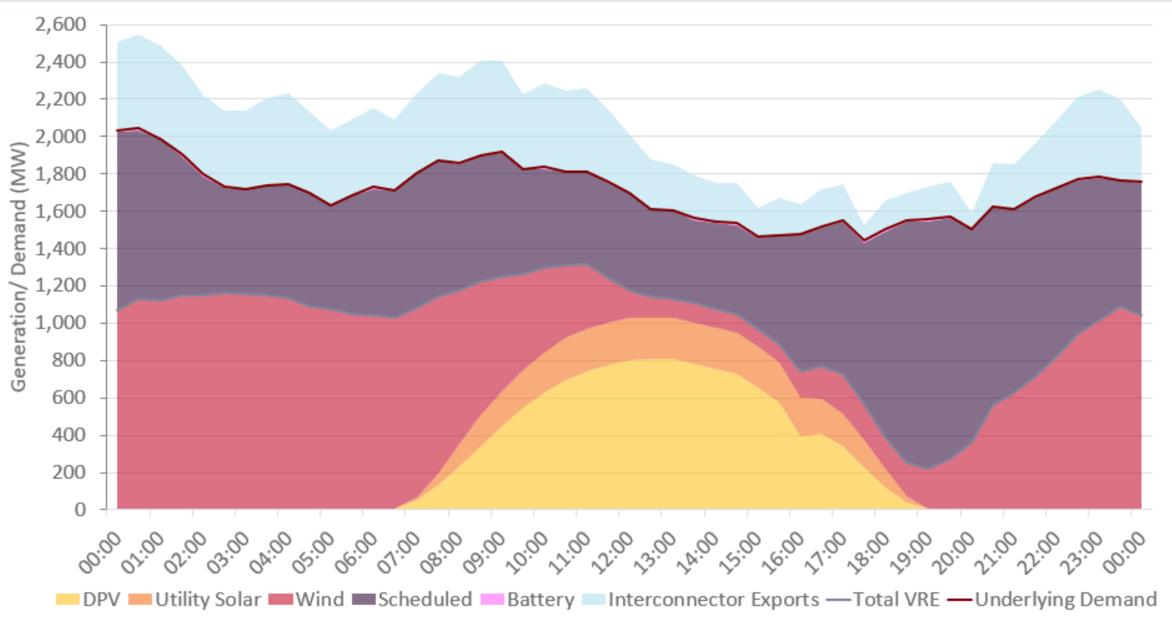
- From midnight to 09:00, **wind generation** was high, producing up to 67% of local underlying demand in South Australia.
- From around 06:30, **DPV and utility solar** ramped up with the sunrise. Over the same period, wind energy reduced considerably. By 12:30, wind was only producing 7% of local underlying demand, while solar resources were producing 64%.

Over this time the changes in solar and wind resources offset one another, meaning VRE did not influence the requirements on the scheduled fleet (including batteries and interconnection).

From around 15:00, solar energy reduced as the sun set and wind energy remained low. At this time, underlying demand also began to pick up towards the evening peak. This resulted in an 810 MW increase in the dispatch of **scheduled generation (both in South Australia and over the interconnector with Victoria)** over four hours.

There is a fundamental change in the nature of the fleet servicing underlying demand throughout the day. During the day, the region progresses from being mainly serviced by wind in the morning, to mainly serviced by solar (utility and DPV) in the middle of the day, to a gas-dominated fleet in the evening (gas is the predominant fuel source for South Australia's thermal scheduled fleet).

Figure 20 Fleet flexibility in South Australia (Saturday, 12 October 2019)



As ramps get larger and faster, operating strategies and potential market changes will be needed to manage the potential for such events. This could include:

- Ensuring interconnectors have sufficient headroom to manage the ramp.
- Ensuring sufficient headroom on dispatchable generation (and load), either locally or connected via the interconnector. This may require starting up plant prior to the ramp (if the ramp is forecast) to ensure that it is online when needed, taking into account start-up times for offline generation.

Over this period, the system strength requirements in South Australia necessitated certain combinations of synchronous generators (gas units in South Australia) to be online to withstand a credible fault and loss of a synchronous generator, at different utility wind and solar output[A]. This system strength requirement has the added benefit of maintaining scheduled units online, which improve the system flexibility to cover ramps in net demand. AEMO directed a unit online at 16:51 to fulfil these requirements (Market

[60] See https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

Notices 70528, 70530 and 70531), however throughout the rest of the day there were enough gas units online to fulfil the requirements.

On this day, batteries contributed a relatively small share to meeting underlying demand. While batteries can move quickly, the existing batteries generally have limited storage and cannot sustain full output over longer periods, such as the solar ramp between 15:00 and 19:00 shown in the figure above.

A. Transfer Limit Advice – System Strength available at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en

C5.2 System capability to meet ramps

With increased variability and uncertainty from higher VRE penetration in recent years, the scheduled fleet has had to alter the way it operates. Many units have had to operate more flexibly than their intended design, with new territory being explored across the NEM around the physical and financial ways that units and portfolios are managed. The aim of this analysis is to:

- Quantify limits to flexibility that may be reached under current operational and market frameworks under the 2025 expansion plan under the Draft 2020 ISP Central scenario .
- Provide a basis for future discussion around new operational tools and supporting regulatory frameworks that may be required for AEMO to manage security risks arising from increasing ramping requirements

The aim of this analysis is to quantify *physical* limits of scheduled plant to provide flexibility, to maximise the utilisation of VRE across the NEM in 2025, under the Draft 2020 ISP Central generation build. Assessment of the costs associated with flexible operating is out of scope of this analysis, however further discussion is needed around appropriate market signals to ensure this flexibility can be delivered, to plan for a system with high VRE penetration.

C5.2.1 Approach

A PLEXOS model was used to simulate dispatch with Short Run Marginal Cost (SRMC) bidding and network constraints included. Under SRMC bidding assumptions, high levels of wind and solar are typically dispatched due to the near-zero SRMC of these technologies, meaning these technologies are typically only curtailed in the model due to physical limits on the network. Dispatch was simulated for the NEM in the financial year ending 2025 under the Draft 2020 ISP Central scenario assumptions, including generation expansion and retirement. Notably, EnergyConnect is operational for the duration of the simulation and Snowy 2.0 is operational from March 2025. See Figure 19 for a summary of fleet and interconnector changes between 2019 and 2025.

SRMC is the change in short run total cost for a very small change in output. It only considers variable costs (fuel, operating costs) and excludes fixed costs (including start-up costs).

SRMC bidding assumes all available generation capacities are bid in at each unit's SRMC. Consequently, this model is fast to solve and renders insights excluding competition benefits.

The analysis focuses on fleet flexibility to cover *upward* ramps in net demand, as large upward ramps in net demand are typically more operationally challenging than a downward ramp of an equivalent size:

- An **upward ramp in net demand** is typically met by sourcing additional generation from the scheduled fleet and interconnectors, subject to factors such as network constraints, unit ramp rates, availability of online generation, and start-up considerations for offline generation. This can be challenging, particularly if the available capacity (headroom) of online generation and interconnection is limited.
- A **downward net demand ramp** can typically be managed more easily by turning down online scheduled or semi-scheduled generation or changing the flow on interconnectors. In the case of constraining down semi-scheduled wind and solar generation, this will have the effect of reducing the size of the net demand ramp that the scheduled fleet is required to cover.

Results are presented for each NEM region, where potential flexibility challenges were identified. Tasmania, due to its large supply of hydro and interconnection relative to regional demand, has not been included in this report, as its challenges in managing variability and uncertainty in 2025 are low.

The ISP provides an integrated roadmap for the efficient development of the NEM over the next 20 years and beyond. Its primary objective is to maximise value to end consumers by designing the lowest cost, secure and reliable energy system capable of meeting emissions trajectory determined by policy makers at an acceptable level of risk[61]. It achieves this in two stages:

- A long-term model which takes a lower granularity view of dispatch to determine the optimal generator and interconnector expansion plan.
- A short-term model which simulates the optimal expansion plan obtained from the long-term model at a half hourly (trading interval) granularity to ensure that the build is operable.

For this analysis on operational flexibility, post-processing was conducted on the short-term model. Full details are outlined in Section C7.2. From a least-cost perspective, it is appropriate for the ISP to run with perfect foresight (no uncertainty) to provide a view of the fleet run as efficiently as possible. To assess the flexibility of the fleet in managing high VRE penetration, steps have been taken to **remove perfect foresight in post-processing** so the data can be analysed from an operational perspective.

Flexibility across operational timeframes

Different sources of flexibility are available over different operational time frames. Ramp windows over 30 minutes, one hour, and four hours were analysed to draw out the relative importance of different technologies in sourcing flexibility over various timeframes. Figure 21 shows the technologies exemplified by each of the ramping windows considered.

Figure 21 Start-up times for modelled flexible resources

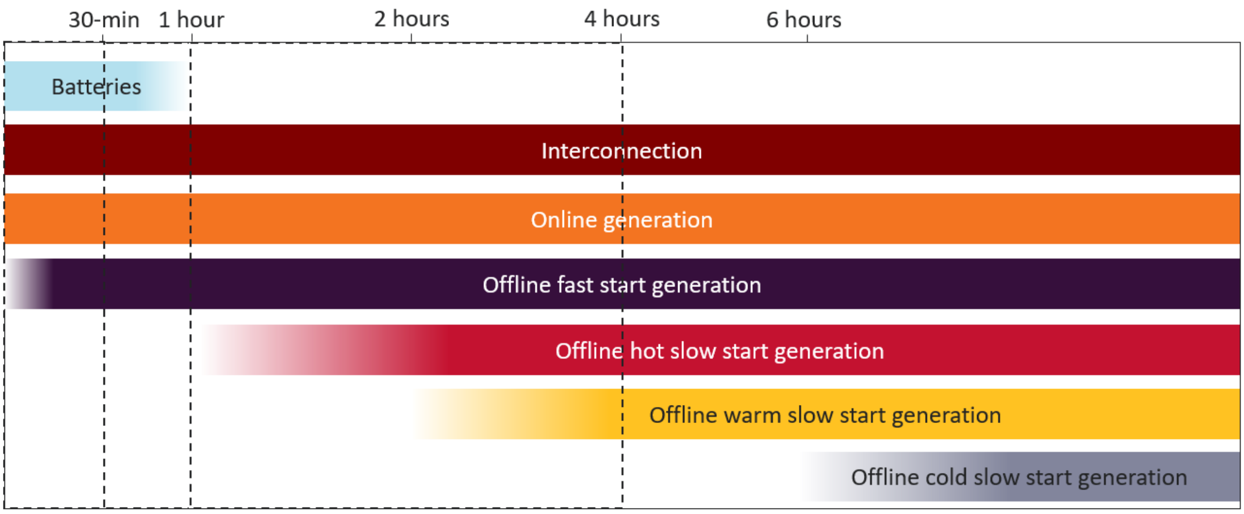


Figure 21 displays the start-up times for current technologies which were modelled in this analysis. These are sources of flexibility for which the market has reasonable operational experience. Modelling did not include many emerging behaviours which may provide flexibility to the NEM by 2025 (see Section C5.1 for a description of some of these technologies). The supplementary materials section (Section C7.2) details how some emerging technologies, including electric vehicles, demand side participation, distributed batteries, and VPPs are accounted for in the PLEXOS model.

[61] For further details on the ISP, including modelling, see https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

As shown in Figure 21, the sources of flexibility that can be accessed to manage ramps over a **1-hour** window are reasonably well known. In addition to interconnection and online generation, which can be accessed over each timeframe, all fast start generation is able to provide flexibility within one hour[62], and offline slow start units are assumed to be unable to synchronise within one hour. Batteries are typically short-duration storage devices that are able provide flexibility over relatively small windows. To accommodate uncertainty regarding battery operation, batteries are assumed to be available to provide half their capacity over the 1-hour ramp windows[63].

Over shorter (30-minute) and longer (4-hour) ramping windows, sensitivities needed to be introduced to explore the range of circumstances that may limit the availability of system flexibility over these windows (see Figure 21). Key sensitivities included:

- **30-minute** – for this ramp window, the immediacy of a response from fast start units to a net demand ramp was assessed as a key determinant of the supply of flexibility. Online generation, interconnection, and batteries[63] were assumed able to start up and operate over 30-minute windows, while offline slow start generation was assumed unable to synchronise within 30 minutes.
  - **Fast start commitment delay** – a delay in the commitment of fast start units may occur due to a range of factors such as failed starts, network communication delays, or changes in market conditions requiring portfolio revision before plant can be committed. This delay is typically expected to be small enough not to significantly impact ramp windows longer than 30 minutes. Commitment delay sensitivities allow for the exploration of the supply of flexibility, by delaying the start-up of the fast start fleet by increments of five minutes. Typical commitment delays fall in the range of five to 10 minutes[64].
- **4-hour** – management of offline slow start units and interconnector headroom were assessed as key sources of flexibility over this timeframe. Online generation and fast start units were assumed able to start up and operate over 30-minute windows, while batteries were assumed to have exhausted their charge within the first hour of 4-hour ramps.
  - **Slow start unit management** – the time taken to start up slow start units depends on the amount of time the unit has been offline. This analysis considers the number of hours since each slow start unit was last dispatched and uses this to determine how much flexibility can be provided by the unit, with units classified as either hot (offline < 8 hours), warm (offline 8 – 48 hours), or cold (offline > 48 hours) at the time of each 4-hour ramp. While it is acknowledged that participants manage their portfolios according to prevailing conditions and risk management strategies (as outlined in Section C2.3.3), predicting this portfolio-specific behaviour is complex, particularly five years ahead, and is out of scope of this work. Sensitivities are presented which consider what flexibility would be available if all offline slow start units were managed to stay warm or stay hot at the time of each ramp. This may be as a result of participant learning and portfolio management to cover commercial risk or AEMO managing risk to system security.
  - **Interconnector headroom** – the available headroom on interconnection that can be sustained over four hours is dependent on the dispatch of generators both locally and in adjacent regions, which may vary significantly over a 4-hour period. Sensitivities were included which assumed interconnector import headroom consistent with the 10th, 50th, and 90th percentiles of interconnector import limits into the region (that is, the minimum capacity which can be imported into the region over interconnection at least 10%, 50%, and 90% of the year as output from the PLEXOS model). These sensitivities assessed a region's reliance on interconnection to meet 4-hour ramps.

[62] By definition, a fast start unit is a unit that can synchronise and reach its minimum loading within 30 minutes, and can synchronise, reach minimum loading, and shut down in less than 60 minutes. For more information, see https://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf.

[63] See Section C7.2 for more details on modelling assumptions for batteries.

[64] This analysis does not consider a commitment delay for batteries, however the issues that lead to commitment delay could equally affect batteries and should be considered in future.

The effect of **net demand uncertainty** has been considered across each ramp window, by assessing the system flexibility that would be required to meet a downward VRE ramp that was 10%, 20%, or 30% larger than forecast.

The sensitivities described above are summarised in Table 16 below.

Table 16 System flexibility post-processing sensitivities

		1-hour ramps	30-min ramps	4-hour ramps
Sensitivities	Net demand	VRE ramp uncertainty: 0% - 30%	VRE ramp uncertainty: 0% - 30%	VRE ramp uncertainty: 0% - 30%
	Fast Start Fleet	No sensitivity (limited impact over 1 hour)	Commitment delay (minutes)	No sensitivity (no impact over 4 hours)
	Interconnector availability	No sensitivity (Modelled limits are available)	No sensitivity (Modelled limits are available)	10th, 50th and 90th percentile of interconnector import limits.
	Slow Start Fleet	No sensitivity (assumed unable to synchronise in less than 1 hour)	No sensitivity (assumed unable to synchronise in less than 30 minutes)	Units kept hot, kept warm or allowed to reach cold status.

Tight flexibility conditions

Section C2.3.3 outlines the ways uncertainty and variability are currently managed in the NEM. This includes both participant management of market and operational risk and AEMO management of risks to security. From an operator perspective, ramping requirements are currently met through FCAS markets or reserve assessment frameworks. While the existing reserve assessment processes (PASA) incorporate a measure of uncertainty (the FUM), they do not incorporate a measurement of the system ramping requirement or available system flexibility to meet this requirement.

This analysis focuses on system flexibility that would accommodate full utilisation of the VRE fleet in 2025, as per the Draft 2020 ISP Central scenario expansion plan. However, it is acknowledged that as the system moves to higher penetrations of VRE, there is likely to be a level of VRE curtailment that is determined by the market to manage variability and uncertainty, as it relates to participant risk and risks to system security.

This analysis identifies the number of **'challenging days'** across the financial year ending 2025. These challenging days reflect periods where a negative ramping margin when maximising VRE was identified in the analysis. Under these conditions, both participants and operators need to manage these margins to ensure the system is secure.

C5.2.2 1-hour ramps

Over 1-hour windows, flexibility from online generators, interconnection, batteries and offline fast start units was assessed, as shown in Figure 21. Offline slow start units were not assessed over the 1-hour window.

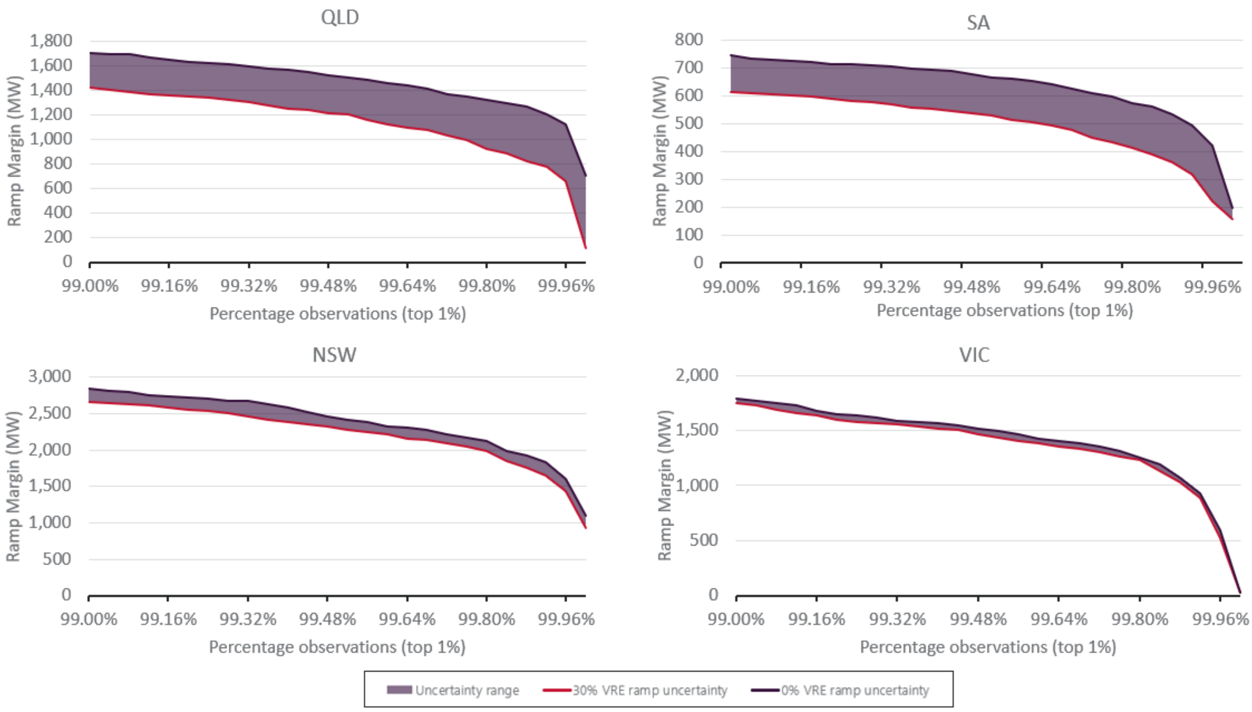
Figure 22 shows the smallest 1% of observed **ramping margins** under a range of uncertainty (the increase in net demand ramp if VRE were to ramp down up to 30% more than forecast). The ramping margin demonstrates the additional flexibility remaining in the system after meeting ramping requirements over a 1-hour window.

The **ramping margin** is the difference between the current ramping capability of the fleet and net demand ramp to be met over a certain time interval. It is the residual flexibility available in the system after covering a net demand ramp.

The ramping capability is a measurement of **flexibility.** It is the number of MW that can be accessed in the system over a set interval.

The analysis projects that each NEM region will have enough flexibility to meet most 1-hour net demand ramps without issue. In the most extreme cases (30% VRE uncertainty, large net demand ramp), the forecast ramping margin is below 200 MW in Queensland, New South Wales, and Victoria[65], which is smaller than the largest credible risk in each region. On these days, it will be critical for both participants and AEMO to ensure there is sufficient ramping margin to manage the risk to customer supply.

Figure 22 1-hour ramps: ramping margin under a range of uncertainty for each mainland region in 2025



Interpreting ramping margin plots

This plot shows the top 1% of smallest ramping margins in 2025. The **coloured lines** show the ramping margin under the best case (no uncertainty; purple line) and worst case (30% uncertainty; red line) cases modelled in this analysis. The **coloured area** between these lines is the range of ramping margin values, given an intermediate level of uncertainty. **Ramps are not met where the lines or coloured area fall below the horizontal axis.** The ramping margin provides a view not only to whether a ramp is met or not, but details how close the fleet comes to not meeting a ramp, or, if negative, by how many Megawatts a ramp is not met.

C5.2.3 30-minute ramps

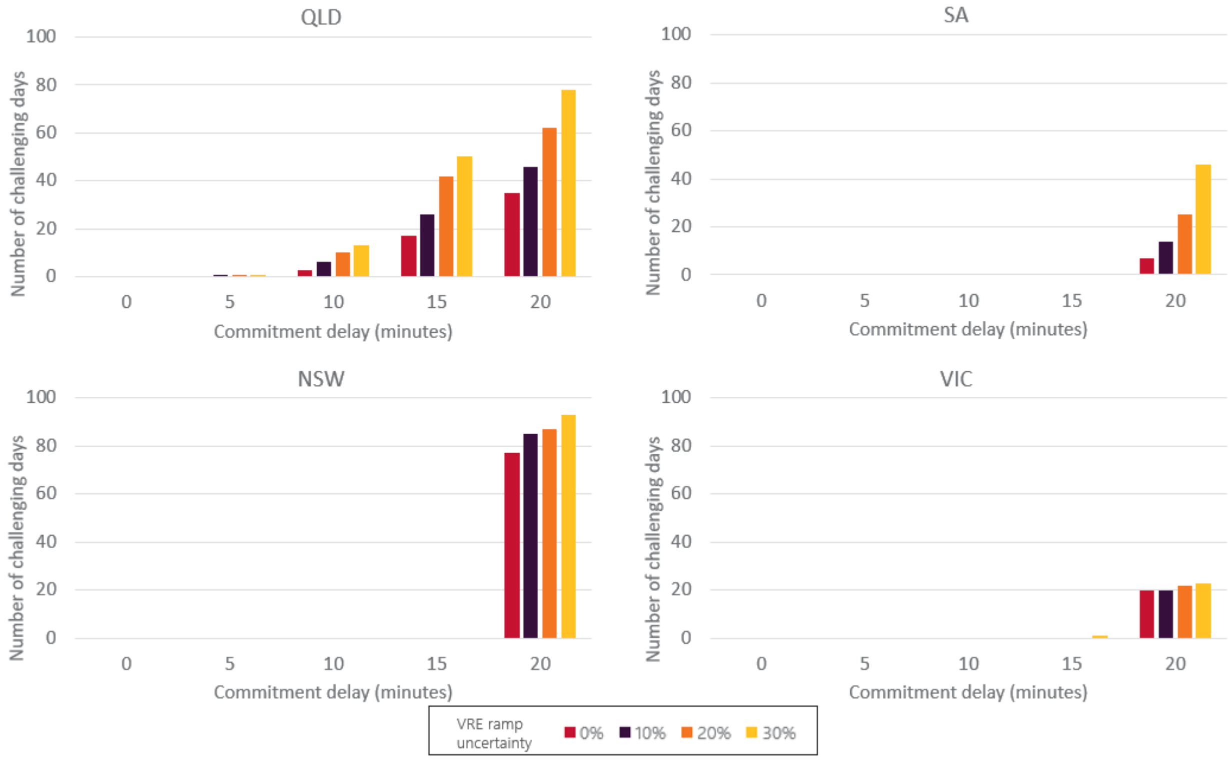
Over 30-minute windows, flexibility from online generators, interconnection, batteries, and offline fast start generation was assessed, as shown in Figure 21. Offline slow start units were not assessed over a 30-minute window.

Flexibility over 30-minute windows is highly dependent on the availability of fast start units and how quickly they respond and start-up (commitment delay). Figure 23 shows that the projected impact of commitment delay is most evident in Queensland, where a commitment delay of 5-15 minutes for all fast start units results in several challenging days. The differences between mainland regions are explored further below.

Ramping margin plots for 15 minutes of commitment delay under a range of uncertainty are available in the supplementary materials section (Figure 29, Section C7.4.4.).

[65] The tightest 1-hour ramping margins in Victoria are characterised by high demand peaks in Summer, when flexibility is low, due to low reserves. During some of these periods, VRE is not ramping down, as such the VRE ramp has not been scaled with an uncertainty factor at these times.

Figure 23 30-minute ramps: number of challenging days under different sensitivities for each mainland region in 2025



Queensland

Under the assumptions stated in section C5.2.1, Queensland is projected to experience the most number of challenging days when meeting ramping requirements over 30-minutes under high VRE penetration by 2025. For example, a commitment delay of 5-10 minutes in the fast start fleet could lead to up to 13 challenging days in 2025.

In the lead up to the tightest ramping margins under a 10-minute commitment delay scenario, Queensland is forecast to be often either importing energy, or to be prevented from importing energy due to constraints which see interconnector headroom availability reduced.

Other regions

30-minute ramping requirements are projected to be able to be covered without significant challenges in New South Wales, South Australia, and Victoria under an assumed commitment delay of 5-10 minutes. New South Wales is not forecast to experience any challenges meeting 30-minute ramps, even with 20 minutes commitment delay, after Snowy 2.0 is modelled operational in March 2025. Although these regions do not experience any challenging days under a fast start fleet commitment delay of 15 minutes or less, modelling shows that under some scenarios New South Wales and Victoria are projected to have under 100 MW of surplus ramping margin, and South Australia to have under 200 MW[66]. With significant delays to fast start response, all else constant, each region is expected to face increase challenges in accommodating VRE and meeting ramping requirements over 30-minute windows. This demonstrates the relative importance of local fast start generation to flexibility, in addition to online generation, batteries, and interconnection.

[66] These results are presented in the supplementary materials section (Figure 30, Section C7.4.4.).

The impact of Five Minute Settlement[67] on fast start start-up signals will be an important factor affecting 30-minute ramping windows by 2025, and should be considered in future assessment of flexibility. For example, Five Minute Settlement is expected to drive increased flexibility in the long term, however its impact in the short term on flexibility is less well understood and should be monitored closely during this transitional period.

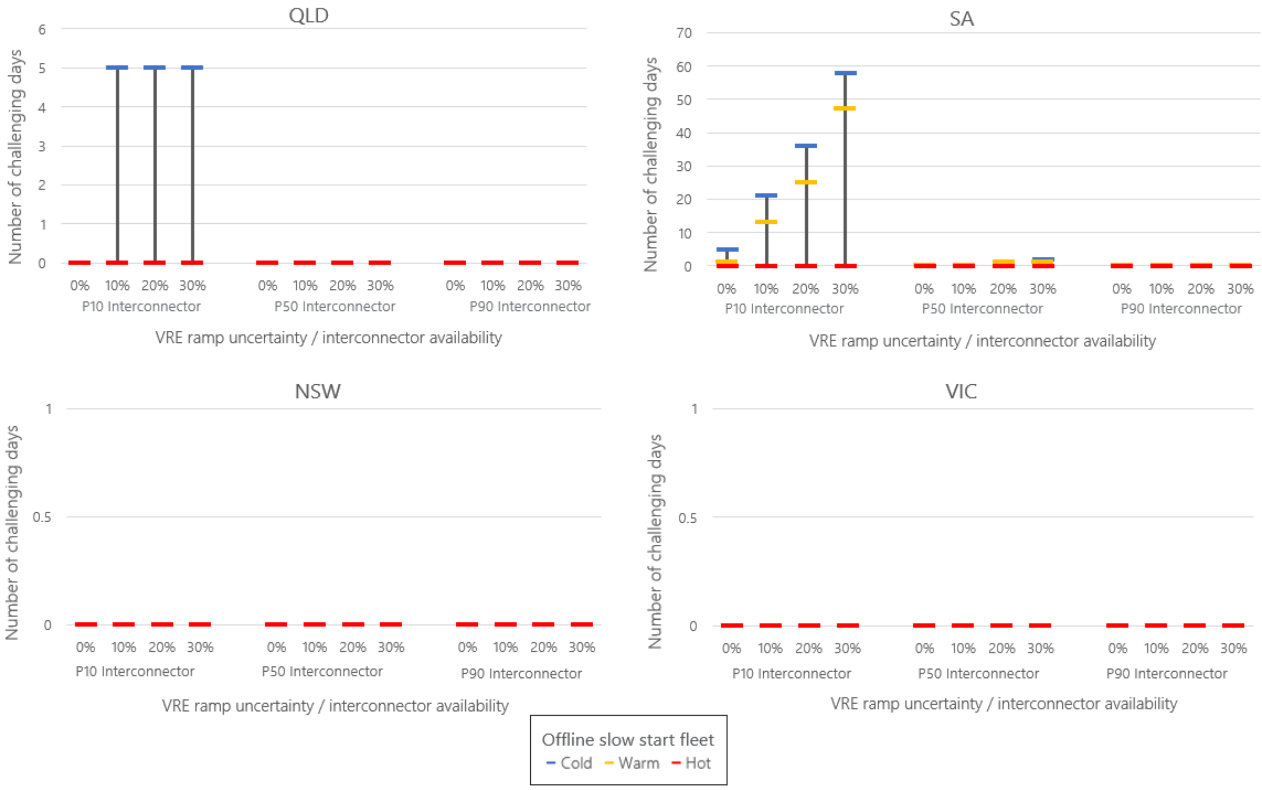
C5.2.4 4-hour ramps

Over 4-hour windows, flexibility from online generators, interconnection, offline fast start units, and offline slow start units was assessed, as shown in Figure 21[68].

Figure 24 presents a view of the number of challenging days forecast in each NEM mainland region, where the available flexibility may not be able to accommodate VRE and cover the ramping requirement. Under current frameworks, these are the days where AEMO may need to actively monitor and manage the system to ensure that the right resources are available at the right times.

The figure shows that the potential challenges in meeting net demand ramps over 4-hour windows are forecast to differ significantly between regions, with South Australia facing some of the greatest challenges. These differences are explored further below.

Figure 24 4-hour ramps: number of challenging days under different sensitivities for each mainland region in 2025



[67] Information on the 5-minute settlement program is available at https://aemo.com.au/en/initiatives/major-programs/nem-five-minute-settlement-program-and-global-settlement.

[68] As described in the approach (section C5.2.1), while batteries may provide flexibility over a 4-hour window, this analysis assumes that batteries have exhausted their charge by providing flexibility in the first hour. As it is the MW change at the *end* of each ramping window that is assessed, batteries have been included in 1-hour and 30-minute analysis, and not included in 4-hour analysis to reflect this assumption.

Interpreting 4-hour flexibility plots

This plot shows the number of days projected for 2025 where there may be challenges managing 4-hour net demand ramps under a range of interconnector, VRE uncertainty, and offline slow start fleet status sensitivities.

Different **interconnector availabilities (P10, P50, P90)** are shown by the clusters of columns along the horizontal axis. P10 represents the 10th percentile of interconnector headroom for the region in 2025, as produced by the model. These sensitivities represent low (P10), medium (P50) and high (P90) availability of interconnector headroom.

Different **levels of VRE ramp uncertainty** are shown by the 4 columns under each interconnector availability cluster.

Start-up times of the offline slow start fleet are shown by the different coloured markers on each column. The number of hours that each slow start unit has been offline since the beginning of the ramp interval is calculated from the model and each unit is assigned a hot (< 8 hours offline), warm (8-24 hours offline) or cold (> 24 hours offline) start up time as appropriate.

For the **cold sensitivity**, the hot, warm, or cold status assigned by the model is retained. For the **warm sensitivity**, all units assigned a hot or warm status by the model retain their status, and units identified as cold are now required to maintain the unit in a warm status. For the **hot sensitivity**, all units assigned a hot status by the model retain their status, and units identified as warm or cold are now required to maintain the unit in a hot status.

Queensland

Figure 24 shows that the most challenging days are projected to be when interconnector availability is low and units in the offline slow start fleet have been offline long enough to become cold. Further investigation identified that these challenging periods in the analysis are characterised by decommitment of some coal units during periods of high VRE penetration, where the decommitted coal units are offline long enough to reach a warm status, and all other forms of slow start units have been offline for longer than two days.

The model projects Queensland to be typically a net exporter in the lead up to the largest 4-hour ramps. This means that there is a relatively large amount of headroom on the interconnector, which can be used to cover ramps. As shown in Figure 24, under median (P50) and high (P90) interconnector headroom scenarios, the challenges posed to the system by variability and uncertainty are low.

While this analysis has identified flexibility challenges if coal units are decommitted during periods of high VRE penetration, there are several other factors that will influence the ramping requirement and supply of system flexibility by 2025. For example, participant learning and changes to operational strategies and bidding behaviour are likely to change as participants gain more operational experience under high VRE periods out to 2025. For example, two-shifting of coal units, VRE pre-curtailment, or hybrid generating systems with both conventional thermal and battery units may become more common.

New South Wales

Figure 24 shows that New South Wales is not forecast to experience significant challenges managing 4-hour net demand ramps in 2025. However, the circumstances under which the tightest ramping margins are forecast to occur in New South Wales are similar to Queensland[69]. These periods are characterised by decommitment of some coal units during periods of high VRE penetration, where the decommitted coal units are offline long enough to reach a warm status, and all other forms of slow start units have been offline for longer than two days.

The modelling shows that, in contrast to Queensland, New South Wales is typically forecast to be a net *importer* in the lead up to the largest 4-hour ramps, which reduces the flexibility available from interconnector headroom. However, New South Wales has access to a greater capacity of local hydro than Queensland. The local hydro availability dominates the smaller interconnector headroom and allows New South Wales to manage 4-hour net demand ramps with a comfortable ramping margin at all times.

[69] Ramping margins over four hours are presented in the supplementary materials section (Figure 30, Section C7.4.4).

South Australia

Figure 24 projects that South Australia will be the region with the most challenging days in 2025.

The most challenging 4-hour windows under moderate (P50) or high (P90) interconnection are characterised by increases in underlying demand during the summer months. The ramp from the solar peak to the evening peak is readily forecastable and subject to low uncertainty, and has historically been managed well. However, as the evening ramp gets larger and faster, there may be a role for new operational strategies or market changes. These would be needed to ensure there is sufficient headroom on dispatchable generation (and load), either locally or connected via the interconnector. This may require starting up plant prior to the ramp (if the ramp is forecast) to ensure it is online when needed.

The most challenging periods identified under low (P10) interconnector headroom are when South Australia has been running on interconnection and VRE alone for more than two days, and offline slow start units are offline long enough to become cold. The model frequently predicts days with these characteristics in 2025, with five to 58 challenging days, depending on VRE ramp uncertainty. However, Figure 24 shows that these challenges are projected to be moderated if median (P50) interconnector headroom can be ensured, with only two challenging days due to other circumstances. Further assessment of the factors that influence interconnector headroom towards South Australia may be warranted to inform potential strategies to ensure interconnector headroom is available at critical times or local flexibility is available.

The following changes would support South Australia operating for prolonged periods with no synchronous generation:

- The introduction of EnergyConnect and synchronous condensers in South Australia before 2025 may lead to relaxation of the requirement to keep local synchronous generators online for system strength. This would result in a reduction in flexibility from system strength requirements, as outlined in Section C5.1.
- Once EnergyConnect is operational, the PLEXOS model, under SRMC bidding assumptions, projects that South Australia will rely more heavily on interconnection than local slow start units to meet demand.

Victoria

No challenging days are forecast for Victoria, with sufficient flexibility to manage 4-hour ramps even under high uncertainty and low interconnection conditions.

With a relatively low SRMC, the model schedules brown coal units in Victoria online more often than black coal units. This means the model outcomes indicate that Victoria has a lower requirement for flexibility than New South Wales and Queensland, where decommitment of black coal units may lead to challenges in supplying adequate system flexibility.

Victoria is a highly interconnected region, as it is linked to three other NEM regions. This means it has access to flexibility over several different interconnectors. Consequently, the low (P10) interconnector headroom is large (1.3 GW) relative to other NEM regions. With the low interconnector scenario involving relatively large levels of interconnection, further work may be required to assess the credibility of a lower interconnector headroom scenario, and what flexibility may look like in scenarios where this occurs.

C5.2.5 Summary

The supply of flexibility to manage variability and uncertainty is dependent on the length of the ramping window, NEM region, market behaviour, and other operational or system events. For example, as seen in the analysis, different technologies have relative advantages over a range of timescales. As such, the fleet composition and interconnectedness of each NEM region will impact how it is able to respond to ramping requirements over different timescales.

Challenges identified under the Draft 2020 ISP Central scenario expansion plan out to 2025 are highlighted by region in Figure 25.

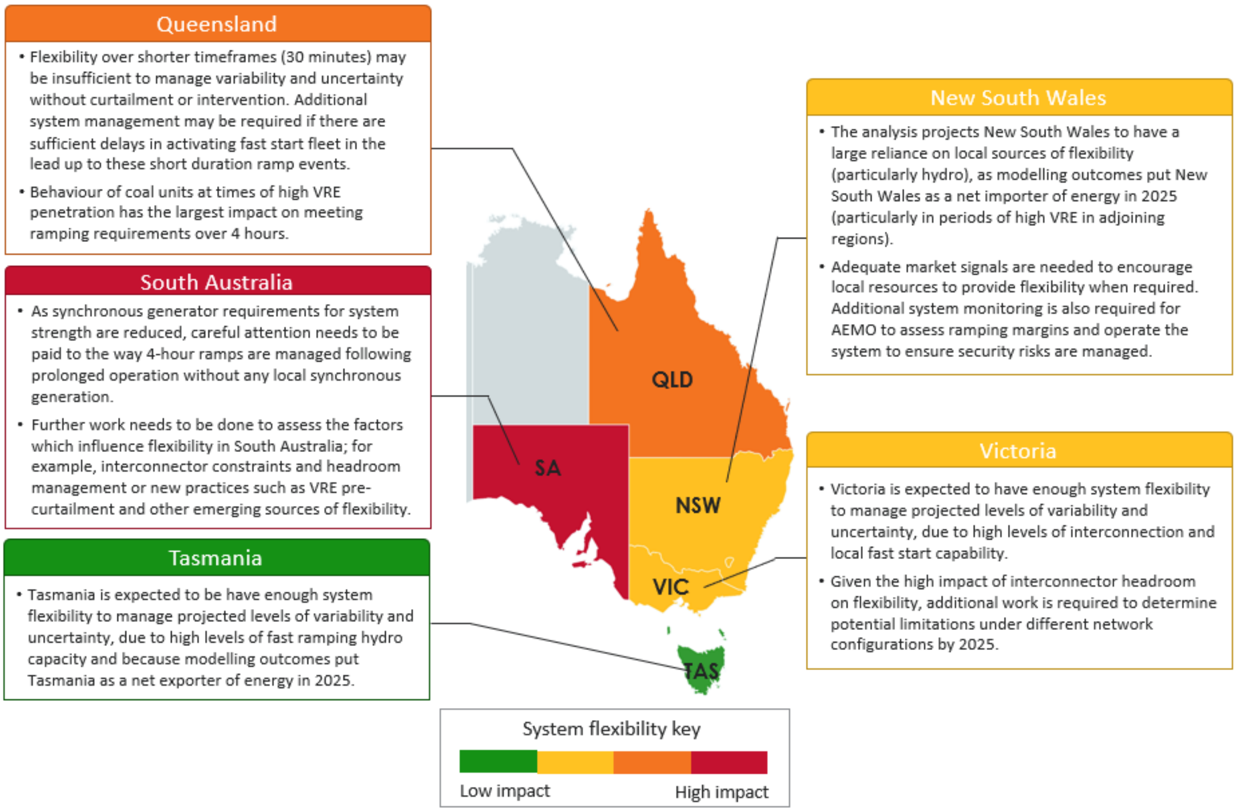
Some key challenges include:

- 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. The analysis highlights that this may be a challenge for Queensland in particular. Careful consideration must go into future market reforms to ensure behaviour which minimises these challenges is encouraged, particularly during the transitional period while new technologies are emerging.
- Delays in the speed of unit commitment for the fast start fleet can create challenges for the system to cover short duration ramps (30-minute windows), particularly during periods of low interconnection headroom. Additionally, new reforms, such as implementation of Five Minute Settlement rule change, before 2025 may impact the commitment decisions of generators over 30-minute windows. For example, Five Minute Settlement is expected to drive increased flexibility in the long term, however its impact in the short term on flexibility is less well understood and should be monitored closely during this transitional period.
- If South Australia operates for a prolonged period of time without any local synchronous generation, then it will be challenging to cover large ramping requirements over 4-hour periods. These conditions become more probable with the introduction of EnergyConnect and synchronous condensers in South Australia before 2025, as the requirement to keep local synchronous generators online for system strength may be relaxed. Further work should be done to assess supply of flexibility under these conditions, including market solutions, headroom management on the interconnectors, and emerging sources of flexibility such as renewable pre-curtailment.

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.

This means there is a need for AEMO to enhance its operational tools to include ramping requirements and flexibility assessments, so tight conditions can be monitored and acted on if necessary. Efficient markets are also needed to appropriately value and incentivise flexibility, as an essential service, when it is needed.

Figure 25 The summary of regional system flexibility to cover projected 30-minute, 1-hour, and 4-hour ramps in 2025



C6. Recommended actions

Wind and solar resources are fast outpacing demand as the key drivers of variability and uncertainty in the NEM. This is increasing the risk to the system that operators may not be able balance supply with demand. In order to manage this risk, two key areas for action are identified:

- **Operational improvements** – enhanced forecasting tools and operational procedures should be explored to manage emerging risks. For example, alternate forecasting approaches, improved weather observation infrastructure, and participant self-forecasting.
- **Increased system flexibility** – appropriate mechanisms must be in place to ensure sufficient flexible resources and network capacity are available at all times to meet the increasingly variable and uncertain system conditions.

Managing future variability and uncertainty will require technical advances, as described above, however markets and regulatory frameworks must also be assessed to facilitate optimal utilisation of these technical capabilities. Solutions considered should also build on considerations from past work, such as the *AEMO observations: Operational and market challenges to reliability and security in the NEM* report[70].

As variability in the system increases, the importance of reducing, quantifying, and communicating uncertainty becomes a key component to maintaining secure operation. The system must be able to deliver adequate flexibility, by predicting when it will be required and ensuring it can be delivered. This will require harnessing flexibility across all aspects of the power system (including from fleet, network, and behavioural components) and ensuring the necessary operational tools, processes and regulatory frameworks are in place to ensure risks arising from increased variability and uncertainty are managed.

C6.1 Operational improvements

To ensure increased flexibility is available when required, AEMO must have the tools to be able to identify and communicate how much flexibility will be required and when. While forecasting improvements are ongoing and will contribute to minimising uncertainty, there will always be some residual uncertainty that must be managed using alternative methods. Being able to quantify and communicate both the magnitude and timing of this uncertainty is essential to managing variability going forward.

Scheduling tools

During periods of high uncertainty, flexibility is required to prepare for all potential outcomes. Keeping flexible plant available for longer periods can be more costly compared to shorter periods, so knowing the timing and magnitude of forecasting uncertainty is essential to the efficient management of flexibility.

The current reliance on operators to manually balance factors and intervene, as described in Section C2.3.3, is becoming increasingly sub-optimal as system variability, uncertainty, and complexity increases. Without

70 At https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.pdf.

effective and standardised operational processes, tools, and training to schedule system strength and inertia services, the risk of human error grows and the level of intervention becomes increasingly unsustainable.

AEMO already incorporates uncertainty, through the FUM, into its reserve assessment processes, ahead of real time. This key enhancement allows a more accurate assessment of required reserves needed to manage uncertainty and maintain reliability. However, the reserve assessment process currently looks only at the technical availability of plant (that is PASA availability, rather than maximum availability) to cover reserves, and includes some simplifications around plant commitment. Improvements to the reserve assessment processes and tools have been identified so they continue to serve the NEM now and in a future dominated by new technologies. This includes assessment of essential services such as ramping requirements and assessment of maximum plant availability (this includes availability based on both technical and commercial reasons), as well as the current technical plant availability (called PASA availability).

Action 2.2	AEMO to redevelop existing scheduling systems (PD and ST PASA) to better account for system needs, including: • Availability of essential system services, including inertia, system strength, and ramping requirements. • Catering for cross-regional sharing of reserves. • Better modelling of new technologies, including VRE, batteries, and DER (including demand response and VPPs).

Forecasting tools

As AEMO gains more experience forecasting with unprecedented levels of wind, solar and distributed resources, many areas are being identified for potential improvements to be made.

- **Ramping forecast and classification prototype** – the current use of deterministic forecasts over operational timeframes is limiting under periods of high uncertainty. Other forecasting approaches, such as probabilistic forecasting or ramping classification tools, can provide a more complete view of VRE uncertainty in operational timeframes (such as identifying high variability or uncertainty periods in a day). Approaches could be developed to forecast the probability of a material ramp over a specific time interval and geographic region, with the aim of improving the commitment of resources to manage ramping.
- **Improved weather observation infrastructure** – the current weather observation network has not been designed for use by the energy sector. In particular, there are a large number of VRE generation assets which are located hundreds of kilometres from the nearest BOM weather station. A new observation network should be considered to enable weather forecasters to more accurately forecast ramping events, with observation sensors deployed strategically around VRE generation assets to provide lead indicators of approaching weather.
- **Participant self-forecasting** – in partnership with the Australian Renewable Energy Agency (ARENA), AEMO launched the participant self-forecasting program to demonstrate the potential benefits of wind and solar generator self-forecasting to operation of the power system. The initial stages of the self-forecasting program are showing improved forecast accuracy, through greater accessibility to local weather information and use of local sensors to provide lead indicators of weather changes (for example, the use of sky imagers to track local cloud movement)[71]. This provides a lead indicator in the short-term models, rather than relying heavily on persistence in the dispatch timeframe.

[71] Further information on participant self-forecasting is at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting/Participant-forecasting.

Action 6.1	AEMO to improve understanding of system uncertainty and risk, particularly during ramping events, by exploring: • Trialling and implementing a ramping forecast and classification prototype. • Deployment of additional weather observation infrastructure that is fit for purpose for the energy industry.

C6.2 Increased system flexibility

To respond to different levels of variability and uncertainty and ensure supply and demand are balanced at all times, flexible resources must be available to provide a mix of both short-term and long-term flexibility. This is in addition to the need for enhanced scheduling and forecasting tools required to monitor the increasing variability and uncertainty. As described in section C5.1, power system flexibility spans more flexible generation, new ways of operating (including new ways of operating VRE), strengthening networks, new technology innovations (including battery storage and demand response). Many advances in flexible technology are already being explored. However, to harness this flexibility in the NEM the right regulatory frameworks must be in place to efficiently value the flexibility that is provided by generators or loads and the costs of variability and uncertainty.

Assessing the suitability of regulatory frameworks for ramping requirements and flexibility should also be considered in the context of other essential services (including system strength and inertia), so that an enduring framework can be established to value the power system requirements that work together to maintain a secure system.

Action 2.3	**2.3** Consistent with the outcomes of this study, the ESB considers that security constrained economic dispatch of energy-only is, by itself, no longer sufficient to maintain system security. The ESB considers that new system services need to be established and remunerated and an ahead market is required to ensure system security going forward[A]. As part of its post-2025 market design program, the ESB is assessing market mechanisms that increase certainty around system dispatch of energy and essential system services (inertia, system strength, minimum synchronous units, operating reserves, and flexibility) as real time approaches. The ESB will recommend a high level design to the COAG Energy Council by end of 2020 for implementation by 2025. A. See http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/ESB%20Post2025%20Directions%20Paper.pdf.
Action 6.2	Improve the reliability of information provided by the VRE fleet to support security constrained dispatch. The ESB is coordinating several interim measures to improve the visibility of and confidence in resources in the NEM, to ensure security can be maintained while new market arrangements are developed[72].

[72] For more information on interim security measures, see http://www.coagenergycouncil.gov.au/interim-security-measures.

C7. Supplementary materials

C7.1 Data

This section describes the data and common assumptions used in sections C3 and C4 of this Appendix.

Historic data

The historical generation data used in this analysis was 5-minute timeseries of generation from semi-scheduled and non-scheduled[73] wind farms and solar farms in the NEM. A ramp is defined as the difference between the start and the end of an interval, with overlapping intervals of five minutes and 60 minutes being explored.

AEMO collected generation output from all semi-scheduled (and some non-scheduled) wind and solar farms through a supervisory control and data acquisition (SCADA) system and used a Plant Information (PI) system to archive the data.

Data between 1 January 2015 and 1 April 2019 has been analysed.

The data was cleaned based on the following rules for individual wind and solar farms, including removal of:

- Erroneous data, including where the data was not marked as good.
- Intervals where new wind or solar farms were commissioning.
- Intervals where a semi-scheduled farm was subject to a semi-dispatch cap.
- Intervals overnight, for solar farms.

These cleaning rules were applied to minimise skewing of ramping statistics due to poor quality data, generation curtailment, and commissioning profiles that are not representative of normal farm output.

Future data

AEMO engaged a consultant (in 2019, Weatherzone and Solcast) to develop generation forecasts for existing and future wind and solar farms for the year 2025, based on the Draft ISP 2020 Central scenario projected build. Forecasts at 1-, 5-, and 30-minute resolutions were provided for wind farm and solar farm locations across the NEM.

In developing the synthetic traces, the following assumptions were made:

- Wind turbine hub height 100 m.
- No high speed cut out events for wind farms.
- No network constraints.
- A single representative point (latitude/longitude) was used for each farm.
- A year was selected that could be considered characteristic of 2025, where 2025 is considered to be an 'average year' under a global warming scenario. This was selected by identifying recent months with major

[73] Where SCADA is provided.

climate drivers (El Nino, Indian Ocean Dipole) in the neutral phase. The months selected were between November 2016 and October 2017.

Net demand

The underlying data for the net demand dataset was the same as the wind and solar variability dataset, with the exception that the data was a 30-minute resolution timeseries of net demand, aggregated at the regional level. Net demand in a region was calculated as operational demand minus semi-scheduled wind and solar and large non-scheduled wind and solar (that is, > 30 MW). Underlying demand in a region was calculated as the demand met by local scheduled, semi-scheduled, non-scheduled, and exempt generation (DER) and generation imports to the region. Underlying demand was used as a proxy for total system demand.

AEMO engaged a consultant (in 2019, Solcast) to develop DPV forecasts for the year 2025, aggregated by region, and scaled to the Draft ISP 2020 Central scenario installed capacity projections. The demand trace for the projected 2025 year leveraged the Draft 2020 ISP Central scenario 50% POE operational demand sent out (OPSO) traces using the same reference year as the wind and solar data, to ensure internal consistency between traces.

Uncertainty

Data from AEMO's AWEFS and ASEFS was used in this analysis. This dataset includes forecasts and actuals for semi-scheduled and some large non-scheduled[74] wind farms and solar farms in the NEM. For forecast horizons from five minutes ahead to one hour ahead, 5-minute resolution data was used, and for forecast horizons greater than one hour, 30-minute resolution data was used.

C7.2 Modelling system flexibility

Model setup

An assessment of NEM fleet flexibility was achieved by post-processing model outputs from the Draft 2020 ISP Central scenario. Key model considerations used in this analysis included:

- **Inputs and assumptions** – Draft 2020 ISP Central scenario inputs and assumptions[75]. This included assumptions that:
  - Four synchronous condensers are installed and operational in South Australia[76], EnergyConnect is completed and operational by 2025, and consequently there are no minimum unit requirements in South Australia in 2025.
  - Snowy 2.0 is operational by March 2025.
- **Bidding model** – SRMC supply bidding model.
- **VRE traces** – AEMO engaged a consultant (in 2019, Weatherzone and Solcast) to develop generation forecasts for existing and future wind farms, utility solar farms, and regional DPV for the year 2025, based on the Draft ISP 2020 Central scenario projected build[77].

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[74] Where AWEFS/ASEFS models are available.

[75] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/2019-to-2020-forecasting-and-planning-scenarios-inputs-and-assumptions-report.pdf?la=en.

[76] See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

[77] Draft 2020 ISP projected installed capacity for 2025 at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-input-and-assumptions-workbook-v1-3-dec-19.xlsx?la=en.

- **Demand traces** – same methodology used for the Draft 2020 ISP Central scenario using a reference year between November 2016 and October 2017[78,79]. This included:
  - Electric vehicles and DER batteries not participating in VPPs included in demand traces[80].
  - Demand side participation as a dispatch outcome activated by spot price triggers.

  The contribution of each of these categories to demand is outlined in the ISP inputs and assumptions workbook[81].
- **Reference year** – a year was selected that could be considered characteristic of 2025, where 2025 is considered to be an 'average year' under a global warming scenario. This was selected by identifying recent months with major climate drivers (El Nino, Indian Ocean Dipole) in the neutral phase. The months selected were between November 2016 and October 2017. This year was used consistently across demand and all generation traces. A consequence of using a single reference year, which represents average conditions, is that the severity of ramping conditions explored may be less than other possible futures.

Post-processing assumptions

The following assumptions have been made during the post-processing analysis:

- **Generator ramp rates** – calculated based on historic data, as the 90th percentile of non-zero ramp rates bid into the market by each unit between the calendar years 2016 and 2019 (inclusive). For units without historic data, ramp rates typical for the unit's technology type were assigned.
- **Ramp window** – the ability of the system to meet a net demand ramp was assessed instantaneously at the end of the ramp window. For example, for a 4-hour ramp window, no assessment was made on the ability of the system to cover changes in net demand over the period leading up to the 4-hour mark. However, analysis of 30-minute and 1-hour windows give an indication of ramp coverage in the periods leading up to the 4-hour window.
- **Unit start type** – scheduled units are registered with AEMO as either fast start or slow start. To be registered as a fast start unit, the unit must be able to synchronise and reach its minimum loading within 30 minutes, and be able to synchronise, reach minimum loading and shut down in less than 60 minutes. Fast start units can submit a dispatch inflexibility profile (including timing parameters, called T-times)[82] which assist with the dispatch of these units over short time frames. Typically, fast start units are gas, batteries, some hydro, and liquid fuel generators. Slow start units are typically black and brown coal, as well as some closed cycle gas turbine (CCGT) and hydro units.
- **Start-up times**
  - Fast start unit start up times were the average of non-zero bid T-times between calendar years 2016 and 2019 (inclusive), to the nearest minute.

    Some hydro units are registered as fast start units but have not bid T-times in the period between 2016 and 2019. These units were assumed to be able to synchronise and reach minimum loading in 10 minutes to reflect the median of fast start hydro units which *have* bid T-times over this period.

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[78] See Market Modelling Methodology Paper at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/market-modelling-methodology-paper.pdf?la=en.

[79] See Electricity Demand Forecasting Methodology Paper at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2019/electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

[80] DER batteries which participate as part of VPPs are able to be scheduled in PLEXOS modelling. How these are dealt with in post-processing is outlined in the post-processing assumptions.

[81] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/2019-to-2020-forecasting-and-planning-scenarios-inputs-and-assumptions-report.pdf?la=en.

[82] Details on T-times and fast start unit inflexibility profile at https://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf.

Most batteries in the NEM are also registered fast start units, but do not bid T-times. As batteries are inverter connected devices, they were assumed to be able to start increasing power at their nominated ramp rate instantaneously.

  – Slow start unit start up was per ISP technical advice[83]. Hot start up times were applied if units were assumed to have been offline < 8hrs, warm start up times were applied if the unit has been offline between 8 and 48 hours, and cold start up times were applied for units offline > 48 hours.

- **Available capacity** – at each 30-minute interval, a snapshot of the current state of the system was taken from the model, including current output and availability for each scheduled generating unit, current flow, and constraints (import and export) on the interconnectors.
- **Batteries** – most utility-scale batteries currently in the NEM have enough energy storage to provide up to one hour of full capacity when fully charged. The following assumptions were made in this analysis to represent typical battery capability:
  – Batteries are at half state of charge and able to provide full capacity for 30-minute ramp windows and half capacity for 1-hour ramp windows.
  – Batteries were assumed to have exhausted charge supplying flexibility in the first hour for ramp windows greater than 1-hour. Batteries may provide flexibility by outputting less than full output for longer, or by cycling charge. However, analysis of these potential behaviours has not resulted in a significant difference in observed flexibility over greater than 1-hour periods.
- **VPPs** – while virtual power plants are able to be scheduled in the PLEXOS model, in post-processing they have been treated as fixed inputs unable to provide flexibility. This has been done due to the uncertainty around how VPPs may be able to operate in the energy market by 2025[84].
- **Snowy 2.0** – Snowy 2.0 was assumed to be able to synchronise and reach minimum loading in three minutes, in accordance with specifications outlined in Section 4.2.4 of its feasibility study[85].

[83] Advice provided by GHD at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/ghd-aemo-revised---2018-19-costs_and_technical_parameter.xlsb?la=en&hash=B4BE15FE1B665E5B63F691E22A6916FB.

[84] AEMO's latest report on VPP trials is at https://aemo.com.au/-/media/files/electricity/nem/der/2019/vpp-demonstrations/aemo-knowledge-sharing-stage-1-report.pdf?la=en.

[85] See https://www.snowyhydro.com.au/our-scheme/snowy20/snowy-2-0-feasibility-study/.

C7.3 Statistical concepts

Concept	Definition	Equation/ example
Population	The entire group of observations which are of interest for analysis.	-
Sample	A subset of the population that analysis is conducted on.	Sample = {1, 3, 3, 6, 7, 8, 9}
Mean	Also called the average. This is the sum of all values in a sample, divided by the number of values in that sample.	$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$ $= \frac{1}{7}(1+3+3+6+7+8+9)$ $= 5.29$
Median	The value at the centre of the sample. That is, the value separating the top half of a sample from the lower half. This is also the 50th percentile value. In a normal distribution, the mean and median are equal.	Median {1, 3, 3, 6, 7, 8, 9} = 6
Maximum	The largest value in the sample.	Max {1, 3, 3, 6, 7, 8, 9} = 9
Minimum	The smallest value in the sample	Min {1, 3, 3, 6, 7, 8, 9} = 1
Percentile	Indicates the value below which a given percentage of observations in a sample will occur. For example, the 90th percentile is the value below which 90% of observations occur. Percentiles can also be thought of in terms of probability of exceedance (POE). So, the 90th percentile is equivalent to the 10% POE value, which is the value that you would expect to be exceeded in 10% of cases (or for historical data was exceeded 10% of the time).	First step is to compute the ramp of the 90th percentile: $R = \frac{np_R}{100} + 0.5$ $= \frac{7 \times 90}{100} + 0.5$ $= 6.8$ If R is an integer, the pth percentile is ramp number R. In this case R is not an integer, so we need to compute the percentile by interpolation: $x_i = (1-f)x_k + fx_{k+1}$ $= (1-0.8) \times 8 + 0.8 \times 9$ Where f is the fractional part of R and k is the integer part, and x_k is the value associated with rank k.
Root Mean Squared Error (RMSE)	The difference between a forecast and the corresponding observed values, which then squared and then averaged over the sample. Finally, the square root of the average is taken. Since the errors are squared before they are averaged, the RMSE gives a relatively high weight to large errors. This means the RMSE is most useful when large errors are particularly undesirable.	$RMSE = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(y_i - \hat{y}_i)^2}$
Recall	The ability of the model to forecast only relevant ramps. That is, given a ramp forecast, the probability that it is correct.	$Recall = \frac{forecast\ \&\ realised}{(forecast\ \&\ realised + forecast\ \&\ not\ realised)}$
Pearson Correlation Coefficient	A statistical test that measures the strength of the linear relationship between two variables. It gives information about the magnitude of associates as well as the direction of the relationship. Pearson's coefficient ranges from -1 to 1.	$r_{X,Y} = \frac{\sum_{i=1}^{n}(X_i - \bar{X})(Y_i - \bar{Y})}{\sqrt{\sum_{i=1}^{n}(X_i - \bar{X})^2}\sqrt{\sum_{i=1}^{n}(Y_i - \bar{Y})^2}}$ • r = -1 is a perfect negative linear relationship • r = 0 indicates no relationship • r = 1 is a perfect positive linear relationship
Precision	The ability of the model to capture all ramps that occur. That is, given a ramp occurred, what is the probability that it was forecast.	$Precision = \frac{forecast\ \&\ realised}{(forecast\ \&realised + not\ forecast\ \&\ realised)}$

C7.4 Additional graphs

C7.4.1 Generation variability

Table 17 Regional 5-minute VRE ramp statistics

	Average		Maximum				99th Percentile			
	MW	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity
New South Wales										
2015	7	1.05%	144	22.19%	-149	-23.02%	35	5.41%	-38	-5.80%
2016	10	0.92%	246	22.52%	-225	-20.62%	45	4.16%	-50	-4.59%
2017	11	0.86%	135	10.38%	-127	-9.75%	48	3.70%	-56	-4.30%
2018	14	0.84%	152	9.31%	-177	-10.79%	55	3.38%	-65	-3.95%
2025	47	1.44%	663	20.36%	-647	-19.88%	257	7.91%	-298	-9.14%
Queensland										
2015	10	0.70%	244	16.82%	-335	-23.11%	25	1.74%	-26	-1.82%
2016	11	0.71%	271	17.12%	-274	-17.31%	31	1.95%	-29	-1.81%
2017	13	0.72%	93	5.07%	-56	-3.07%	35	1.90%	-34	-1.84%
2018	18	0.79%	295	12.91%	-268	-11.73%	62	2.72%	-57	-2.50%
2025	42	0.97%	861	19.83%	-695	-16.02%	209	4.82%	-238	-5.48%
South Australia										
2015	10	0.69%	185	12.41%	-267	-17.87%	52	3.46%	-50	-3.32%
2016	11	0.72%	246	16.45%	-356	-23.82%	53	3.55%	-51	-3.44%
2017	12	0.70%	265	15.58%	-199	-11.75%	60	3.53%	-58	-3.41%
2018	13	0.73%	200	11.06%	-199	-11.01%	64	3.55%	-63	-3.51%
2025	29	1.17%	386	15.72%	-564	-23.01%	134	5.46%	-197	-8.05%
Tasmania										
2015	4	1.37%	107	34.68%	-111	-35.97%	26	8.44%	-25	-8.08%
2016	4	1.45%	161	52.11%	-163	-52.84%	27	8.70%	-27	-8.62%
2017	4	1.35%	104	33.77%	-166	-53.77%	24	7.86%	-23	-7.44%
2018	4	1.42%	113	36.56%	-114	-37.08%	25	8.12%	-24	-7.70%
2025	7	1.29%	209	37.16%	-172	-30.62%	43	7.60%	-49	-8.64%
2015	9	0.87%	210	19.92%	-212	-20.08%	52	4.93%	-51	-4.79%
Victoria										
2016	10	0.84%	190	16.35%	-276	-23.77%	49	4.25%	-51	4.41%%

	Average		Maximum				99th Percentile			
	MW	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity
2017	11	0.80%	232	16.53%	-238	-16.95%	55	3.95%	-56	-4.02%
2018	13	0.86%	268	17.65%	-245	-16.16%	59	3.91%	-65	-4.27%
2025	52	0.91%	714	12.49%	-947	-16.57%	238	4.15%	-316	-5.52%

Table 18 Regional 1-hour VRE ramp statistics

	Average		Maximum				99th Percentile			
	MW	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity
New South Wales										
2015	44	6.71%	563	86.76%	-401	-61.74%	240	37.05%	-228	-35.08%
2016	76	6.92%	565	51.71%	-430	-39.34%	300	27.51%	-302	-27.69%
2017	91	7.01%	490	37.66%	-554	-42.61%	353	27.17%	-368	-28.33%
2018	114	6.95%	587	35.83%	-657	-40.11%	444	27.14%	-475	-29.03%
2025	308	9.45%	1,904	58.48%	-1952	-59.97%	1,543	47.40%	-1,497	-45.98%
Queensland										
2015	122	8.43%	614	42.27%	-630	-43.40%	274	18.86%	-269	-18.53%
2016	134	8.42%	581	36.65%	-542	-34.20%	305	19.21%	-297	-18.75%
2017	162	8.78%	432	23.47%	-448	-24.33%	369	20.04%	-358	-19.41%
2018	205	8.97%	653	28.56%	-709	-31.01%	538	23.54%	-483	-21.15%
2025	338	7.79%	2280	52.52%	-2,113	-48.69%	1,918	44.18%	-1,702	-39.23%
South Australia										
2015	58	3.85%	535	35.84%	-453	-30.32%	250	16.75%	-232	-15.51%
2016	65	4.38%	504	33.75%	-612	-40.95%	267	17.89%	-270	-18.05%
2017	73	4.30%	932	54.92%	-605	-35.64%	309	18.22%	-309	-18.22%
2018	86	4.73%	867	47.96%	-656	-36.30%	358	19.79%	-350	-19.36%
2025	158	6.45%	1238	50.46%	-1,052	-42.90%	581	23.69%	-641	-26.14%
Tasmania										
2015	17	5.60%	240	78.05%	-236	-76.62%	93	30.07%	-88	-28.56%
2016	18	5.94%	248	80.45%	-231	-74.97%	95	30.88%	-89	-28.95%
2017	18	5.69%	187	60.58%	-220	-71.40%	87	28.28%	-77	-25.07%
2018	19	6.12%	171	55.56%	-196	-63.67%	93	30.24%	-89	-28.80%
2025	29	5.12%	274	48.74%	-256	-45.48%	126	22.43%	-130	-23.11%

	Average		Maximum				99th Percentile			
	MW	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity	Positive (MW)	% of Capacity	Negative (MW)	% of Capacity
Victoria										
2015	49	4.67%	537	50.88%	-493	-46.65%	234	22.14%	-239	-22.60%
2016	63	5.45%	436	37.48%	-659	-56.69%	245	21.13%	-264	-22.73%
2017	75	5.36%	679	48.41%	-598	-42.59%	292	20.82%	-292	-20.80%
2018	92	6.09%	628	41.42%	-704	-46.45%	356	23.48%	-362	-23.86%
2025	316	5.53%	2,214	38.71%	-2374	-41.52%	1,335	23.34%	-1,276	-22.31%

C7.4.2 Geographic distribution

Figure 26 Historic pairwise correlation by distance, farms < 250 km

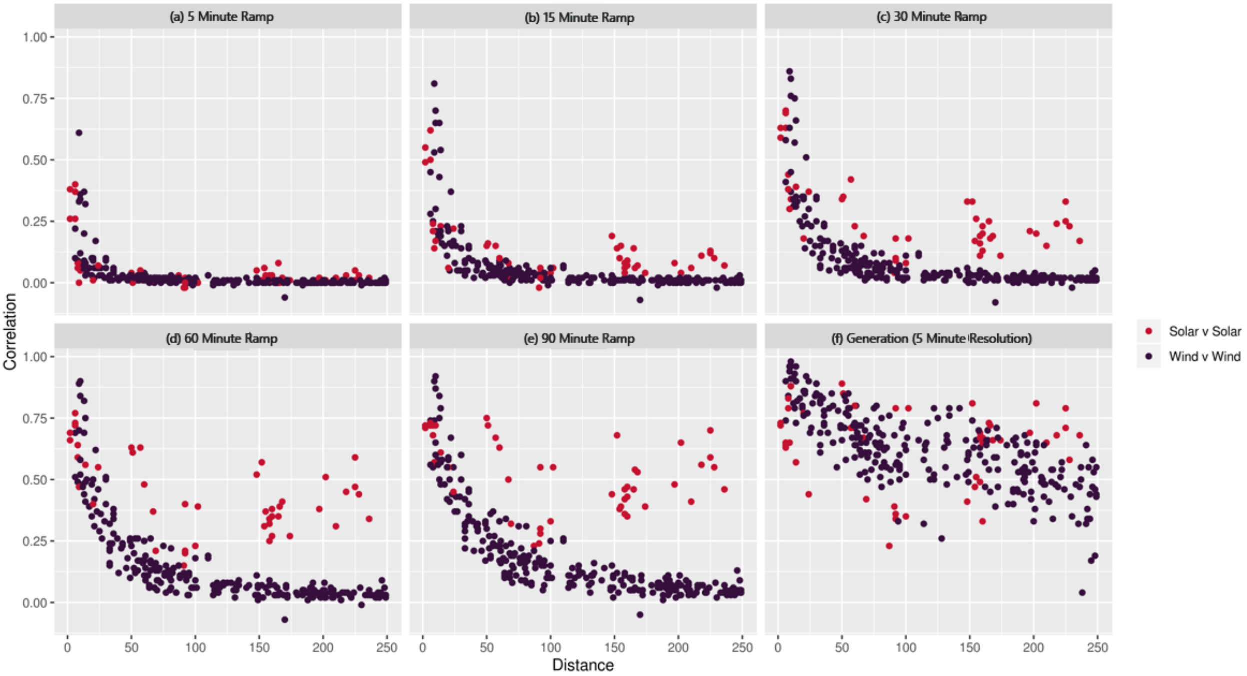
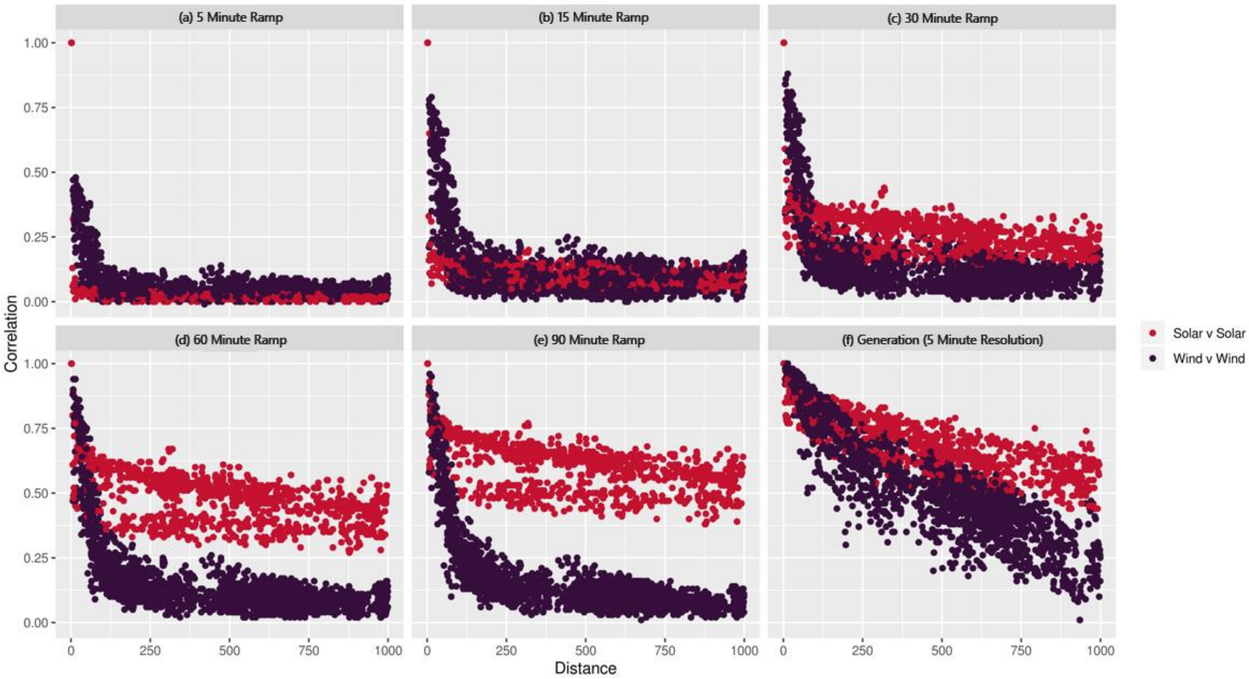


Figure 27 2025 pairwise correlation by distance, farms < 1,000 km



Note: Synthetic data for some adjacent farms were modelled at the same latitude and longitude, giving 100% correlation in the synthetic graphs. For example, Bungala SF 1 and 2, Oakey 1 and 2, etc.

C7.4.3 Net demand

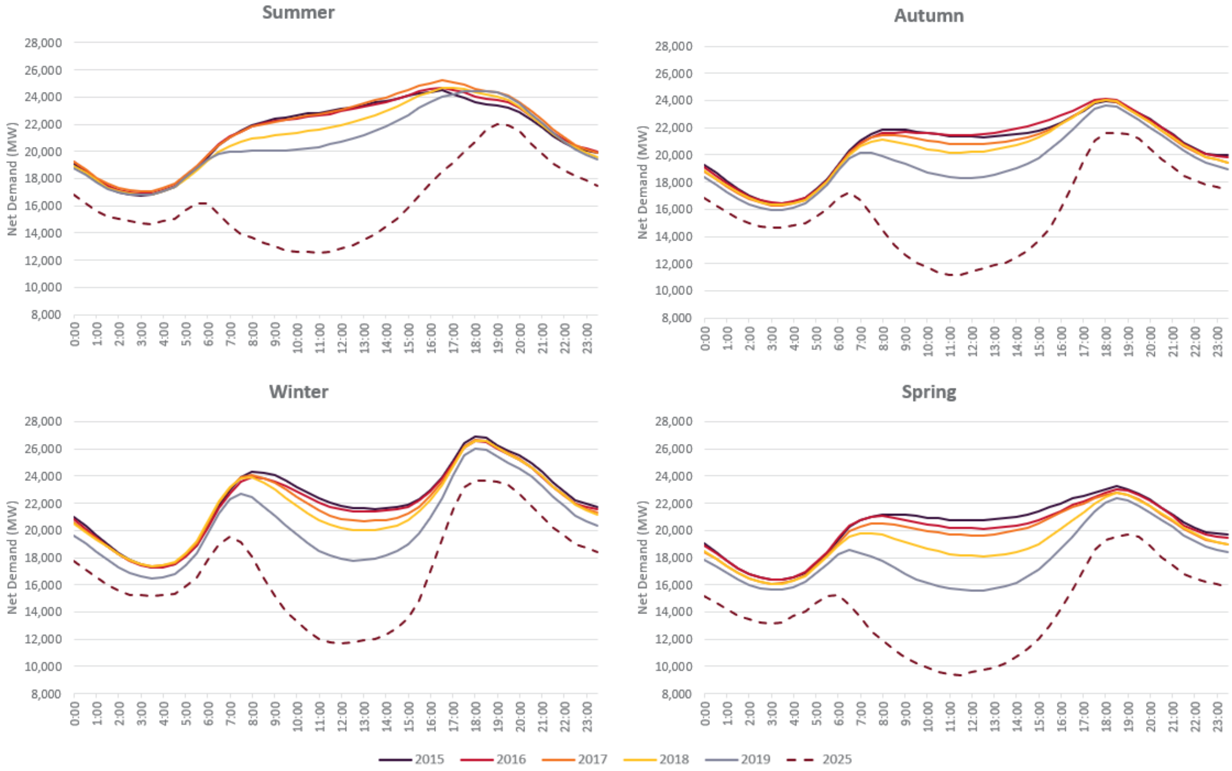
Table 19 Regional 1-hour net demand ramp statistics

	Average	Maximum		99th Percentile	
	MW	Upward (MW)	Downward (MW)	Upward (MW)	Downward (MW)
New South Wales					
2015	320	1,824	-1,105	1,439	-670
2016	316	1,740	-1,176	1,380	-693
2017	321	1,801	-1,198	1,405	-727
2018	329	1,834	-1,143	1,446	-710
2025	415	2,406	-1,796	1,811	-1,263
Queensland[A]					
2015	-	-	-	-	-
2016	167	687	-426	563	-330
2017	166	603	-232	538	-225
2018	222	979	-854	745	-653
2025	377	2,223	-1,971	1,730	-1,485
South Australia					
2015	99	573	-669	331	-312

	Average	Maximum		99th Percentile	
	MW	Upward (MW)	Downward (MW)	Upward (MW)	Downward (MW)
2016	100	545	-516	341	-331
2017	105	609	-928	363	-369
2018	113	584	-957	399	-383
2025	169	918	-1,133	609	-542
Tasmania					
2015	45	521	-398	204	-132
2016	42	265	-360	188	-128
2017	44	273	-252	193	-126
2018	44	239	-244	181	-129
2025	50	327	-281	205	-150
Victoria					
2015	223	1164	-914	917	-571
2016	223	1140	-1036	902	-581
2017	232	1143	-1115	933	-627
2018	222	1128	-961	875	-576
2025	366	2,343	-1,820	1,374	-1,177

A. Queensland data has been omitted for 2015.

Figure 28 Seasonal net demand curves, 2015 to 2025



C7.4.4 Flexibility

Figure 29 30-minute ramping margin with 15 minutes commitment delay under a range of uncertainty for each mainland region in 2025.

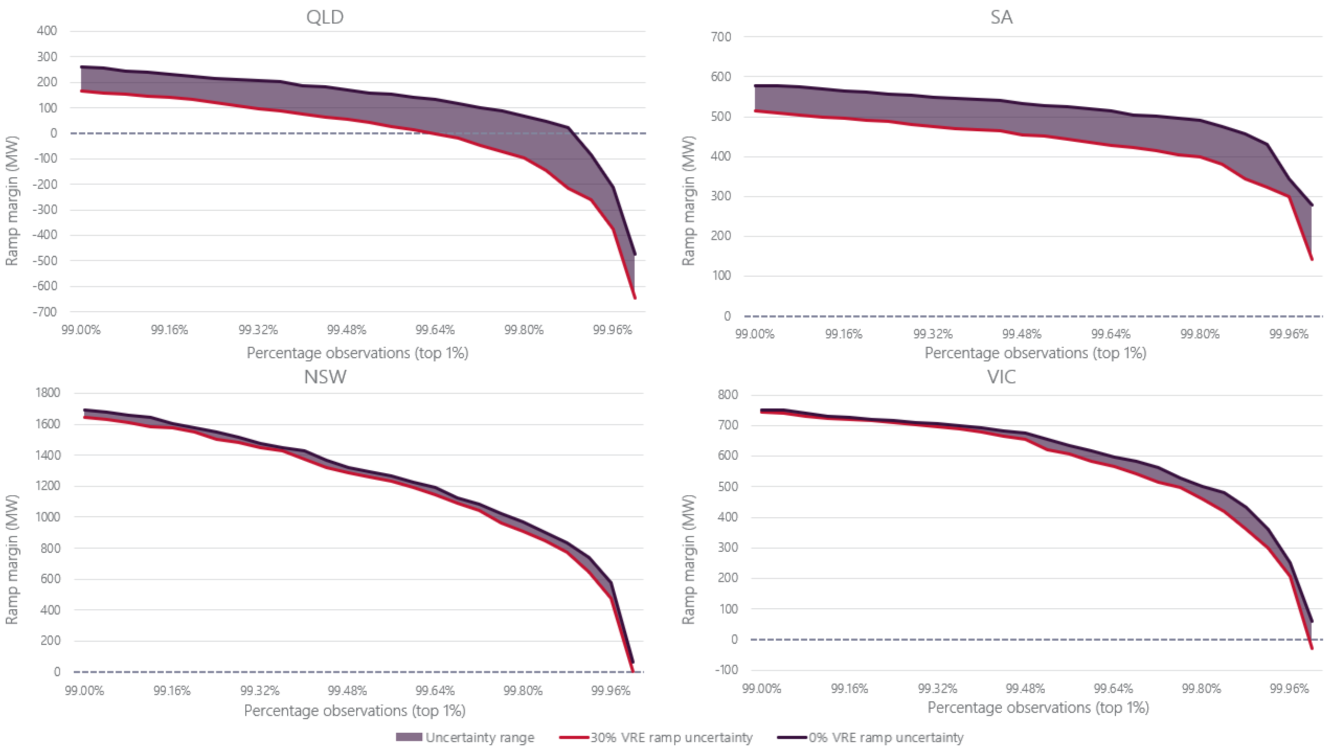
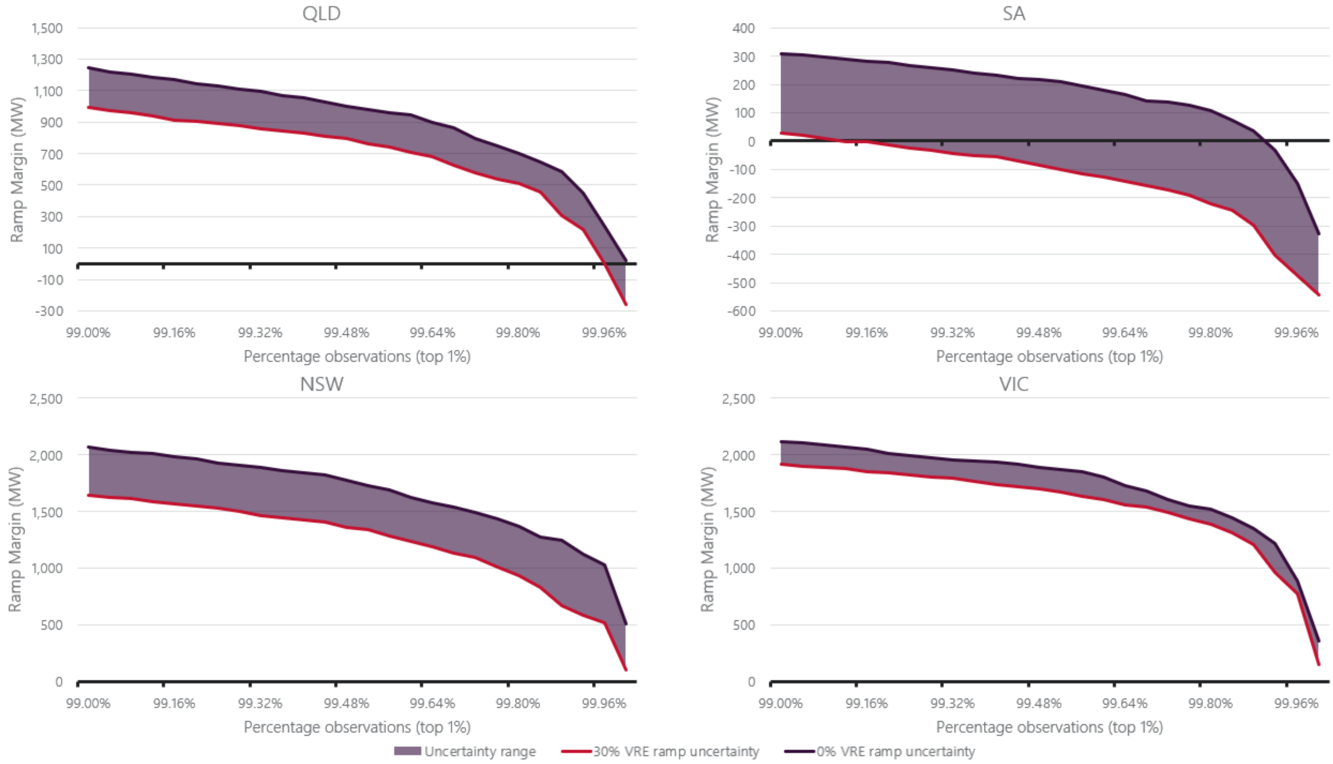


Figure 30 4-hour ramping margin with Low (P10) interconnector headroom and offline slow start units allowed to cool under a range of uncertainty for each mainland region in 2025.



Abbreviations

Abbreviation	Description
AEMO	Australian Energy Market Operator
AGC	Automatic Generator Control
ASX	Australian Stock Exchange
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
BOM	Bureau of Meteorology
COAG	Council of Australian Governments
DER	Distributed energy resources
DPV	Distributed Solar Photovoltaic
ESB	Energy Security Board
FCAS	Frequency control ancillary services
FUM	Forecast Uncertainty Measure
GW	Gigawatt – one billion (10^9) watts
ISP	Integrated System Plan
kW	Kilowatt – one thousand watts
LOR	Lack of Reserve
MAE	Mean Absolute Error
MW	Megawatt – one million watts
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NOFB	Normal Operating Frequency Band
NSP	Network service provider
NSW	New South Wales
NWP	Numerical Weather Prediction
OCT	Over the Counter

Abbreviation	Description
OPSO	Operational Demand Sent Out
PD PASA	Pre-Dispatch Projected Assessment of System Adequacy
PI	Plant Information
PPA	Power Purchase Agreement
PV	Photovoltaics
QLD	Queensland
RERT	Reliability and Emergency Reserve Trader
RIS	Renewable Integration Study
RMSE	Root Mean Square Error
SA	South Australia
SCADA	Supervisory control and data acquisition
SRMC	Short Run Marginal Cost
ST PASA	Short Term Projected Assessment of System Adequacy
TAS	Tasmania
VIC	Victoria
VPP	Virtual Power Plant
VRE	Variable renewable energy