

Appendix A4. System Operability

June 2026

Appendix to the 2026
Integrated System Plan for the
National Electricity Market





We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO is proud to have launched its Innovate [Reconciliation Action Plan](#) (RAP) in June 2026. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This is Appendix A4 to the 2026 Integrated System Plan (ISP) which is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>. AEMO publishes the 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 20 April 2026 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	25/06/2026	First release



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Executive summary

AEMO's *Integrated System Plan (ISP)* is a roadmap for the National Electricity Market's (NEM's) transition, and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet Australia's future energy needs.

The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies.

This appendix contributes to the 2026 ISP by providing detailed assessments of system operability as the NEM transitions to higher shares of variable renewable energy (VRE), demonstrating the ODPs resilience to historically observed variations in weather, with projected changes to demand. It details how, in the *Step Change* scenario:

- **Consumers' use of electricity will continue to evolve**, driven by the continued uptake of consumer energy resources (CER), the electrification of industry, businesses, homes, and transportation, and the expansion of data centres. More of that growing consumption will be self-supplied by their own devices, and increasing rooftop and small-scale solar will continue to drive higher excess supply available during daylight hours.
- **Increasing variable VRE penetration adds operational complexity**, as operating the power system with fewer synchronous generators and greater variability will present daily, weekly and seasonal challenges to maintaining power system reliability, security and energy adequacy. Investments in storage assets will firm VRE, enabling surplus energy to be stored and used later to meet demand when renewable resources are less available. Solar generation will become the main energy source during daylight hours, complemented by wind energy across the day and night. Storages and hydro will be important in firming and shaping supply to demand. Geographic and technological diversity of the supply mix will help reduce the energy adequacy risks of poor weather conditions, while flexible gas and other dispatchable resources will back up this diverse resource mix.
- **Periods of renewable potential that exceed 100% of demand are expected to become more frequent in the future**, and it is projected that some level of VRE curtailment (either economic offloading¹ or network curtailment²) will be more efficient than building sufficient network investments and storage to allow all excess generation to be used or stored for future use. Modelling indicates that forecast NEM-wide annual curtailed VRE remains below 20% across the horizon, although VRE in some renewable energy zones (REZs) may be constrained significantly more than the NEM-wide average, with most unused potential energy resulting from economic offloading rather than transmission limits.
- **'Renewable lulls' of longer dark and still weather create challenging conditions**, and storages will be heavily relied on to shift energy to when it is most required, including existing hydro schemes which are able to shift energy seasonally over weeks and months and may be operated strategically. Flexible gas generation, and surplus generation transmitted through the transmission and distribution networks from regions less affected by poor weather conditions, will also support ongoing reliability during these conditions.

¹ Economic offloading refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. May also be referred to as economic 'spill' as generators reduce output due to low market prices or lack of available demand.

² Network curtailment refers to a generator being dispatched below its economic availability (output available at offer prices below the regional reference price) due to the operation of network- or security-related constraints.



A4.1 Introduction

This appendix of the 2026 ISP provides additional analysis on the operability and reliability of the power system given the forecast demand conditions, the generation and storage developments, and network developments that are identified in the ODP. It presents a granular assessment of operational dynamics and reliability challenges as the power system transitions to much higher levels of VRE, and demonstrates the resilience of the ODP to these challenging conditions. In this appendix:

- A4.2 examines how demand profiles will continue to evolve and the impacts on power system operations.
- A4.3 analyses the requirement for resource flexibility to manage increased variability in supply and demand.
- A4.4 discusses approaches for coal generators to operate more flexibly in a system dominated by renewables.
- A4.5 provides forecasts and analysis for VRE penetration and curtailment.
- A4.6 investigates the role of storage technologies in firming VRE.
- A4.7 examines the operational resilience of the ODP during extended long dark and still weather conditions.
- A4.8 summarises the reliability outcomes for the ODP and provides insights into seasonal reliability risks.

The content in this appendix is complemented by Appendix A7, which quantifies NEM system security requirements and provides insights into the nature, timing, and geography of the services needed to address them.

Key changes from the Draft 2026 ISP³

- Reflected known generation and storage developers' interests by including the connections pipeline until 2030 to increase the ISP's projected capacities' alignment with actual connection interests. Implementing this resulted in some utility-scale solar being replaced by wind and utility-scale storage in the near term.
- Included additional utility storage, utility solar, and wind capacity by 2029-30 that now meet the criteria to be classified as committed or anticipated, as per the January 2026 Generation Information update.
- Updated the consumer batteries and virtual power plant (VPP) forecasts to capture the Federal Government's Cheaper Home Batteries Program (CHBP), including the impact of these updates on the half-hourly demand profile.
- Updated the implementation of hydrogen electrolyser demand in the time-sequential model to better align with the capacity outlook model. This includes an updated assumption in both models that there is sufficient hydrogen storage to store a month's worth of hydrogen to improve flexibility and ability to absorb VRE, based on stakeholder feedback.
- The VRE drought analysis in this appendix has been extended to include an assessment of operational reliability during longer VRE lulls and the potential role of strategic storage management for future storage operations.

³ AEMO has published all inputs and assumptions in the 2026 ISP Inputs and Assumptions Workbook, including a change log of changes.



A4.2 The NEM's demand profiles will continue to evolve

As Australia transitions to a net zero emissions future, electricity consumption and demand will continue to change, with new loads and uses for electricity bringing new ways and times to use electricity, and as consumers continue to use their own electricity from their own CER. Increasingly, traditional electricity uses will be incentivised to match their use of electricity to times when supply of renewable energy is most available. This evolution from building supply to meet the needs of consumers to adapting energy use to match supply (through flexible loads, or energy shifting capabilities provided by batteries) will improve the operability, but also increase the complexity, of the power system.

There are several key drivers of change impacting the forecast demand profile:

- Consumers will increasingly use their own consumer resources in rooftop solar, batteries and electric vehicles (EVs), make investments that improve energy efficiency, and make behavioral choices that change the way they draw power from the grid.
- Increasing demand for digital services (from digitalisation, artificial intelligence (AI) uptake and cloud-based computing adoption) is driving a forecast expansion of data centres, which is projected to increase electricity consumption despite increases in computational efficiency.
- Households and businesses seeking to reduce emissions are projected to electrify processes and appliances that have traditionally used fossil fuel, such as natural gas used for space heating, and petrol or diesel in vehicles, leading to a rise in electricity consumption and peak demand.
- Population growth and increased economic activity are projected to continue increasing electricity use, and major industrial loads face the need to reduce emissions, leading to forecast increased use of electricity in manufacturing, mining and other major industrial processes.

Figure 1 illustrates how demand patterns in the NEM are projected to evolve over time, including showing the growing influence of CER, electrification, and consumer preferences for charging dynamics on the forecast time-of-day demand⁴. Multiple EV charging profiles are applied to capture different driver charging behaviours, including time-specific EV load which is responsive to time of use (TOU) tariffs that incentivise charging when solar energy availability is high⁵. The difference between underlying demand and operational demand is expected to be met by generation from rooftop and other small-scale solar during the day and discharge from passive CER storage in the evening and overnight.

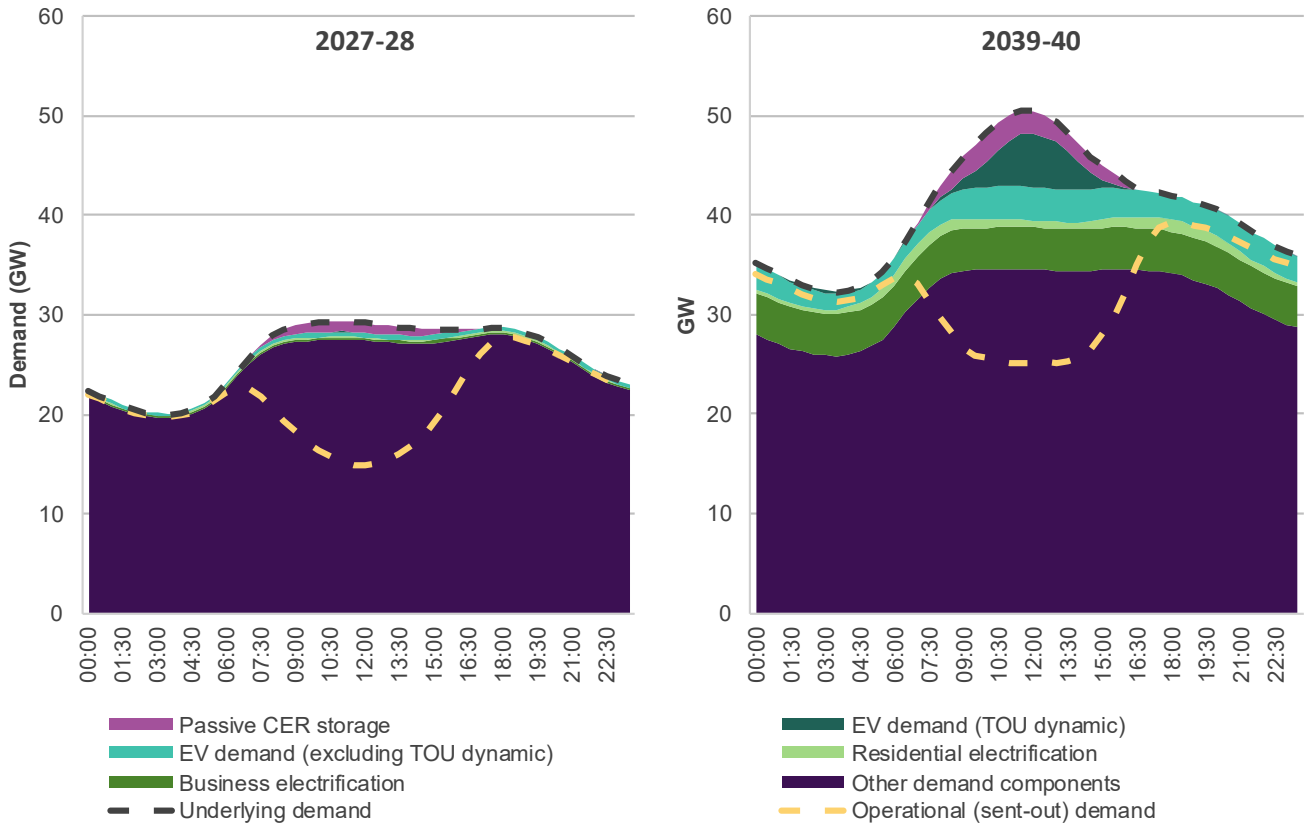
By 2039-40, overall consumption and the evening peak demands are higher, while storage and EV charging is projected to be concentrated in the middle of the day to absorb surplus generation from growing rooftop and other small-scale solar. This results in a projected operational demand profile with a wide, deep trough when rooftop and other small-scale solar generation is highest, and sharper changes in demand for the morning and evening peaks as the sunlight rises and fades at the beginning and end of each day, leading to more use of the grid to supply consumers that were using their own resources.

⁴ Additional information on the forecasts used for the 2026 ISP, including for scenarios other than *Step Change*, is published in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios>.

⁵ For more information on the different EV charging profiles, refer to Table 17 in the 2025 IASR.

This shift underscores the growing influence of CER and emerging technologies on grid demand, alongside the continuing challenge of managing evening peaks and minimum system load conditions (that is, when high output from rooftop solar combines with low underlying demand, resulting in extremely low operational demand).

Figure 1 Projected time-of-day average demand profile for the NEM⁶, 2027-28 and 2039-40, Step Change (gigawatts [GW])



Demand definitions used in this appendix:

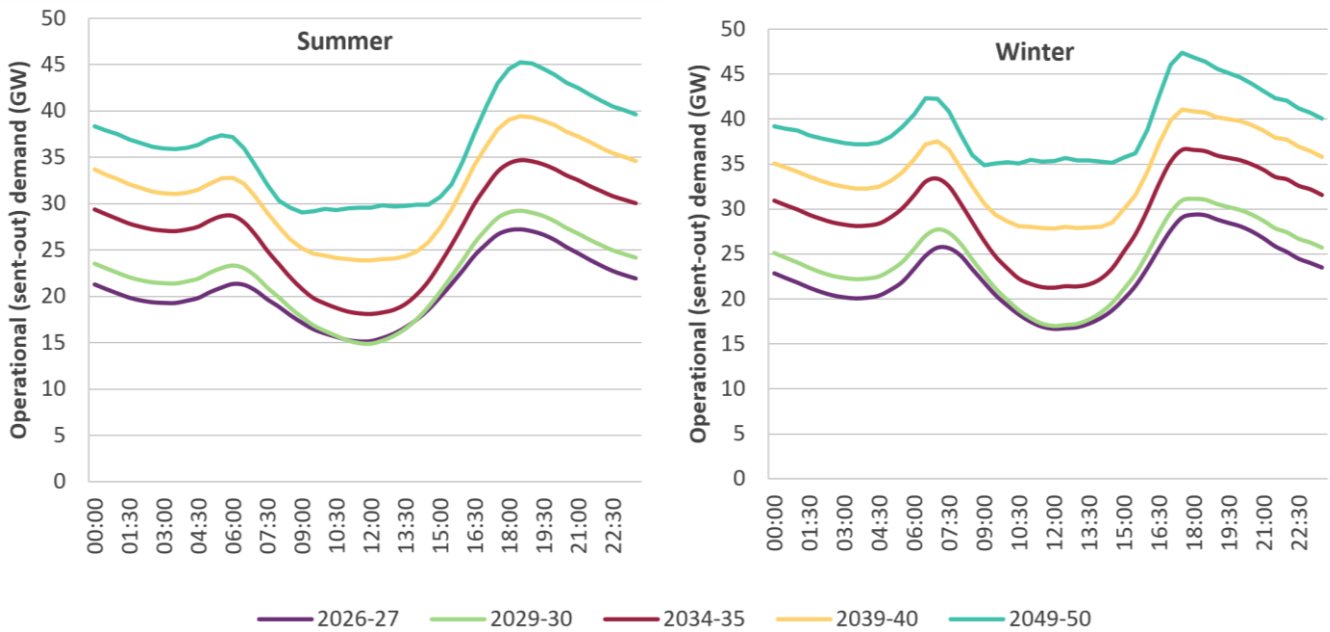
- **Operational (sent-out) demand** refers to demand supplied from the national power system (or grid).
- **Minimum operational demand** means the lowest level of demand from the grid in any day, week or year.
- **Underlying demand** encompasses all the electricity used by consumers, including electricity sourced from the grid and other sources including consumers' rooftop solar and battery storage.
- **Residual demand** refers to the operational demand left over after generation from grid-scale VRE is removed; that is, the operational demand remaining to be met from dispatchable generation sources.

⁶ The full dataset for the 2026 ISP demand traces is published under the 2026 ISP Traces heading at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.



Figure 2 illustrates the projected average time-of-day operational demand profiles for summer and winter seasons. The upward trend in both seasonal curves reflects forecast strong growth in electricity consumption driven by electrification, EV uptake, population growth, data centre expansion and hydrogen demand. Heating and cooling devices are significant influences on seasonal load patterns, and particularly drive up demand for electricity during extreme temperature days, as customers use their energy devices to improve their thermal comfort.

Figure 2 Forecast time-of-day average half-hourly NEM operational demand profile, summer and winter, Step Change, 2026-27 to 2049-50 (GW)



Over time, summer peaks are forecast to rise due to higher cooling demand and electrification impacts. Winter profiles show steeper growth in the mornings and middle of the day, consistent with the ongoing adoption of electrified space heating as customers shift away from energy forms such as gas and wood heaters, supported by commercial decisions by consumers when replacing end-of-life assets and various government policies supporting electrification.

During summer, the deepening midday trough, particularly noticeable between now and 2034-35, highlights the influence of rooftop and other small-scale solar, whereas winter retains a flatter midday curve due to reduced solar contribution. Over time, midday troughs in both seasons are expected to be offset by additional load from EV and battery charging, and while batteries will discharge in the evenings, driver preferences introduce more uncertainty for EVs. EV charging may increase evening peaks, increase overnight demand and/or increase daytime charging while some EVs will be equipped in future to provide a store of energy through vehicle-to-home (V2H) and vehicle-to-grid (V2G) services. A steep ramp in operational demand between the solar trough and the evening peak is projected to remain evident, particularly in summer, and highlights the importance of flexible generation to respond to this need, as discussed in Section A4.3.

Weather and behavioural patterns are hard to predict and are significant influences on the needs to develop infrastructure that is resilient to weather variations to support customer load. This underscores the challenge of managing increasing peak demand and greater supply and demand variability during the energy transition.



A4.3 System flexibility manages increased variability

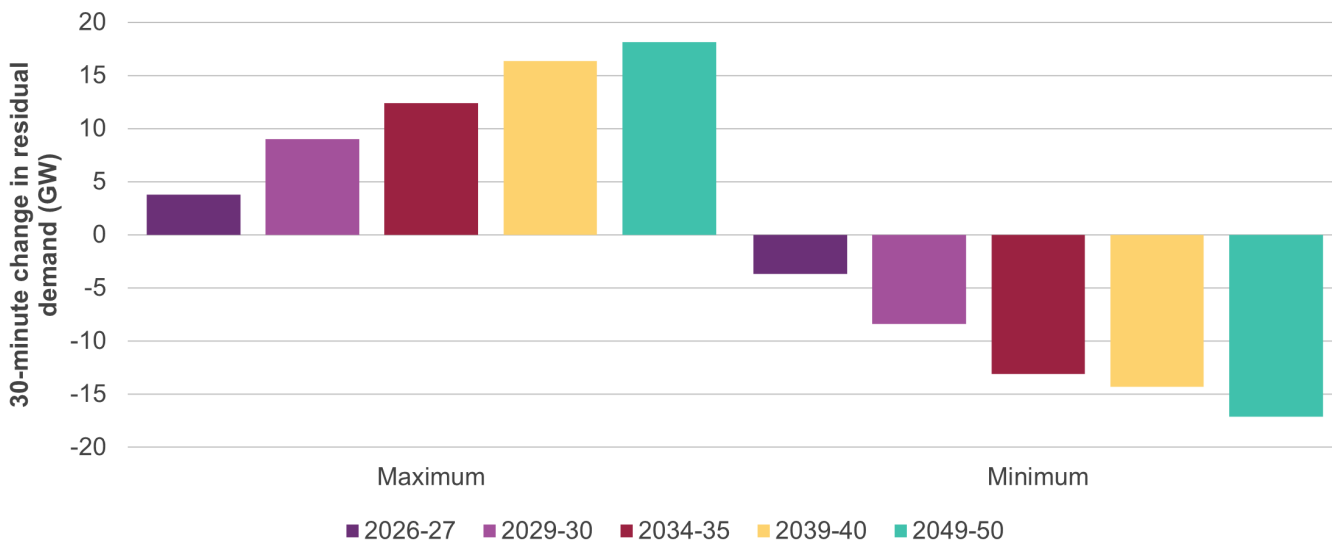
Resource flexibility is required to manage increased variability of electricity generation and demand. Residual demand in this appendix refers to the electricity demand that is met by dispatchable generation, or the demand that is net of VRE generation. The level of residual demand is increasingly volatile, due to the inherent variability of VRE generation and the increasing impact of consumer energy resources and how those investments are utilised. The residual demand profile used in this analysis assumes a level of coordinated CER storage and, as shown earlier in **Figure 1**, the remaining passive CER storage follows an assumed operating profile. Different consumer behaviours may impact system flexibility requirements in future.

Rapid and more frequent changes to residual demand across the power system will require firm resources to have sufficient ramping capability across all operational timeframes. Increased ramping requirements are typically associated with local wind speed fluctuations, daily diurnal solar profiles, and much faster, less predictable ramps from clusters of rooftop solar and other small-scale solar due to localised cloud movements. Managing the operational requirements of firming technologies, including consideration of real-time ramping requirements to accommodate the variability of VRE and operational demand, will be important to operating the NEM securely and reliably.

Analysis in this section is based on modelled dispatched outcomes that reflect operational conditions, taking into account factors such as economic offloading, network curtailment and operational dispatch due to generator bidding behaviour.

During the period to 2049-50, average residual demand is projected to reduce significantly as additional VRE is installed but is also expected to become much more variable. **Figure 3** below shows the maximum and minimum changes projected in half-hourly NEM-wide residual demand over a year in *Step Change*.

Figure 3 Projected maximum and minimum changes in half-hourly NEM-wide residual demand, *Step Change*, 2026-27 to 2049-50 (GW)



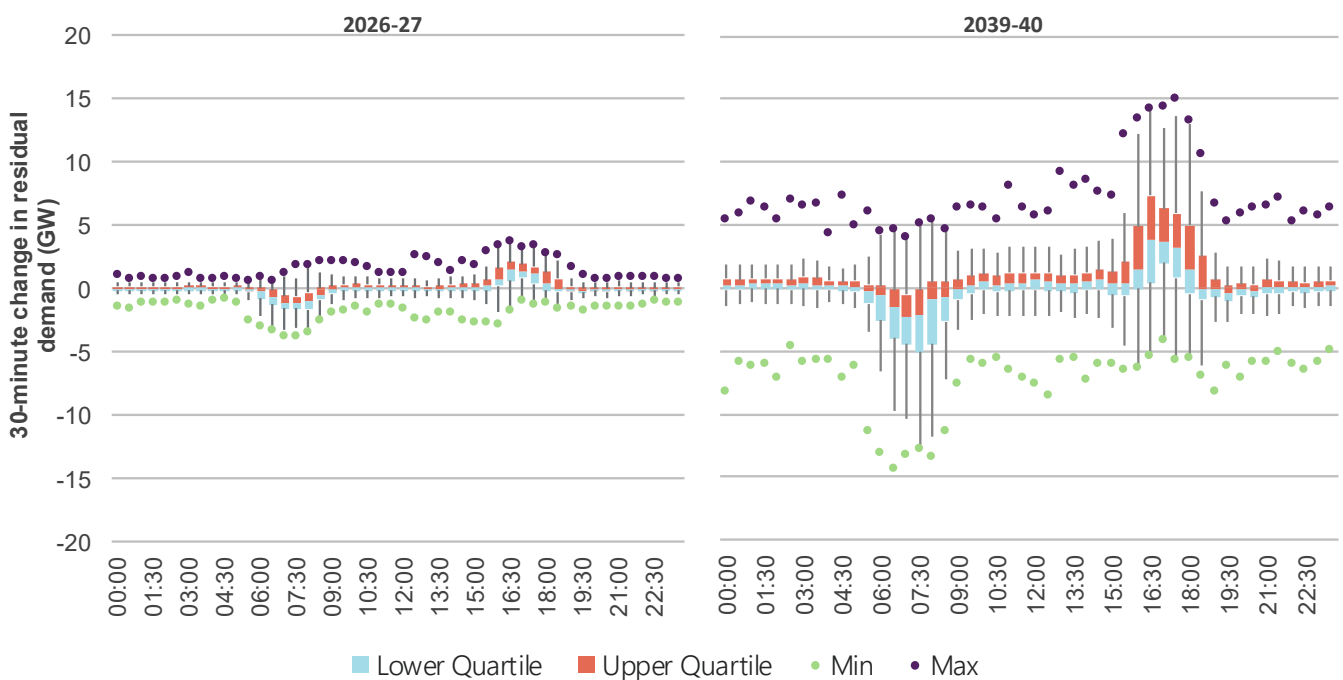
Residual demand fluctuations become more extreme as the capacity of utility solar and rooftop and other small-scale solar grows. While variations in wind generation also contribute to ramping requirements, wind speed fluctuations tend to be more localised, and therefore less impactful when considering a geographically diverse generation mix developed across multiple REZs. The largest changes in residual demand are projected to occur at dawn and dusk, following the solar



generation profile. These periods are highly predictable and therefore less challenging for NEM operations. Less predictable ramping at other times presents a more significant challenge for NEM operations. A record coincident half-hourly ramp up occurred on 26 November 2025, with operational demand increasing by nearly 2.5 gigawatts (GW) in New South Wales and 2 GW in Queensland over 30 minutes as bands of fast-moving cloud cover crossed Sydney and Brisbane at approximately the same time.

Figure 4 shows the projected distribution of residual demand changes for each half-hourly period over the course of a day in 2026-27 and 2039-40.

Figure 4 Projected time-of-day distribution of half-hourly NEM residual demand changes, Step Change, 2026-27 (left) and 2039-40 (right) (GW)



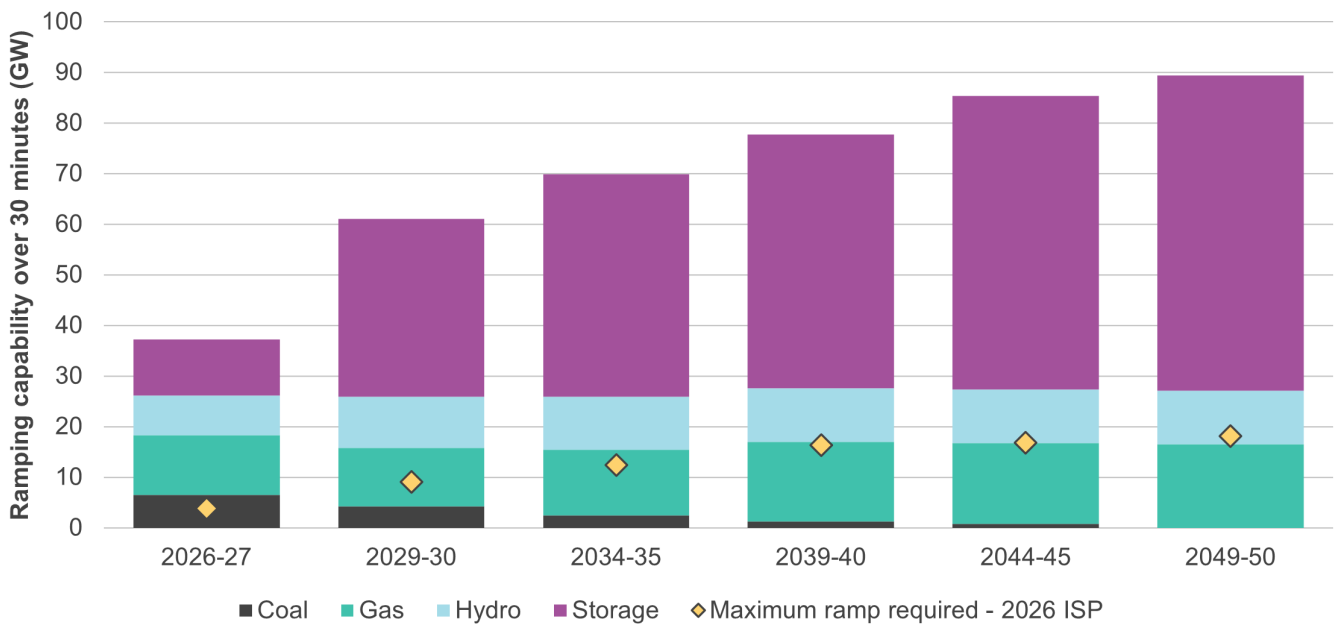
In the future, utility storage (including pumped hydro) and coordinated CER storage are projected to become the primary providers of system flexibility, but flexible gas and hydro will continue to provide significant ramping capacity. Increasingly flexible modes of operation for coal generators may be able to provide some ramping capacity, however this is not expected to be as responsive as storage, gas and hydro.

Figure 5 shows the projected maximum ramp up capability in gigawatts for each 30-minute period across the dispatchable generation fleet in the ODP. This represents the combined flexibility across all units operating in the system.

It is important to note that during daily operation, the actual ramping capacity at a unit will vary according to its online status, current generation, and, in the case of storage, the level of stored energy at that time. The ODP develops firm capacity throughout the planning horizon to match growing demand and balance VRE intermittency and availability.



Figure 5 Forecast maximum ramping capability of dispatchable generation, Step Change, 2026-27 to 2049-50 (GW)



Note: Dispatchable generator categories include coal (black and brown coal generators), gas (flexible gas, mid-merit gas, biomass and diesel generators) and storage (utility storage and coordinated CER storage).

Figure 6 presents the projected NEM generation mix during a day in 2034-35 when a peak 14.5 GW ramp up, equivalent to 41% of underlying load, is required at approximately 1700 hrs due to significant generation reduction from solar while load remains relatively high⁷. This is an example of the more predictable type of ramping event that occurs in the evening following the solar storage generation profile.

Storage technologies and hydro generators contribute most of the ramping required by rapidly discharging stored energy or utilising hydro reserves to generate, with coal and gas generators providing the rest of the ramping requirement. In cases where stored energy and other dispatchable generation is insufficient to meet demand, voluntary demand side participation including demand response may need to be deployed.

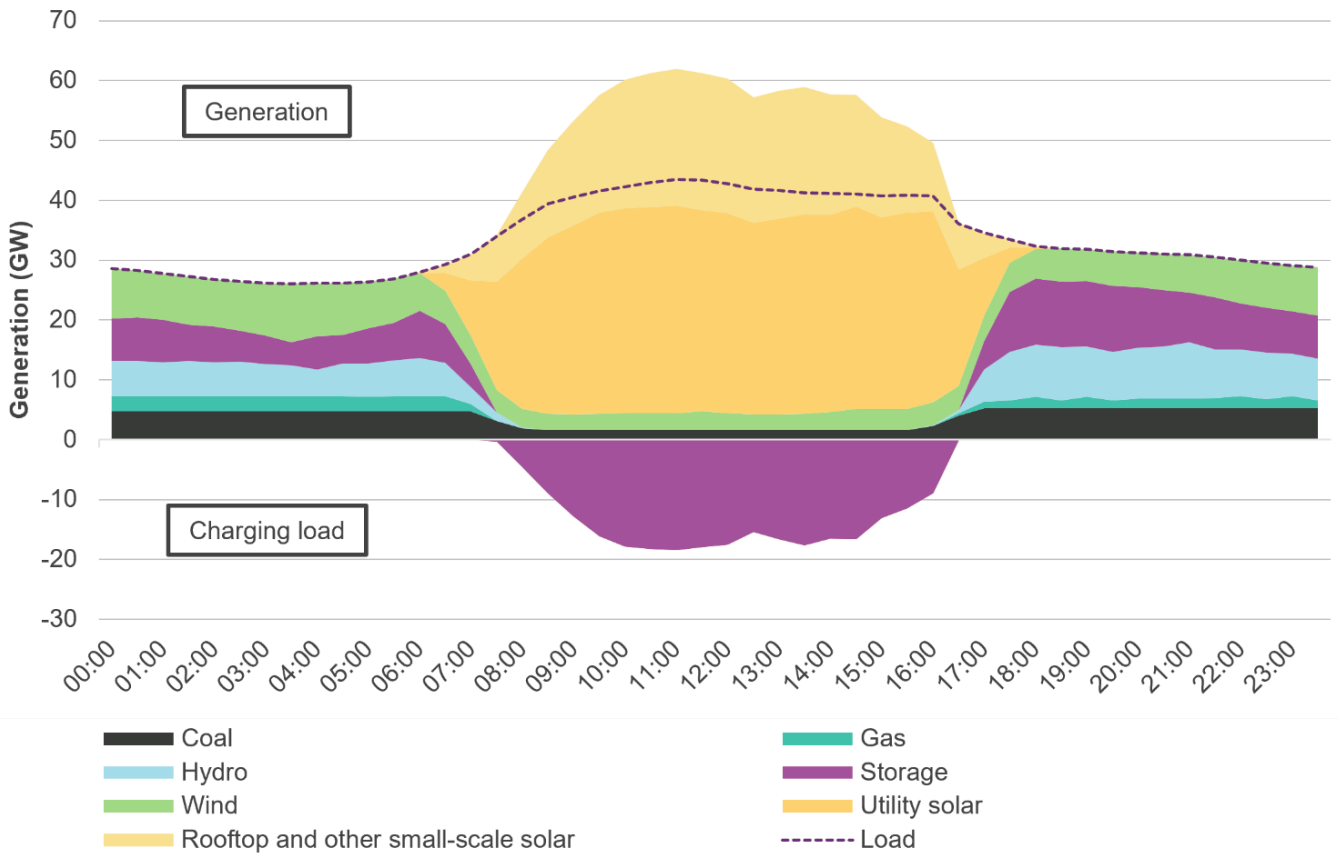
Storage dispatchability is projected to become crucial to the reliability and security of the power system. Further discussion on the role and needs for storage firming is in Section A4.6.

This assessment does not address the need to maintain grid security and the provision of critical frequency and voltage control services. Appendix A7 System Security and the 2025 *Transition Plan for System Security* provide more detail regarding system security and engineering requirements for secure operation of the power system.

⁷ While this significant ramp up event occurs in 2034-35 in the ISP modelling, the actual timing of ramping events is dependent on the weather, consumer behaviour, and other operational factors.



Figure 6 Projected NEM generation mix on a day with maximum ramp, Step Change, 2034-35 (GW)





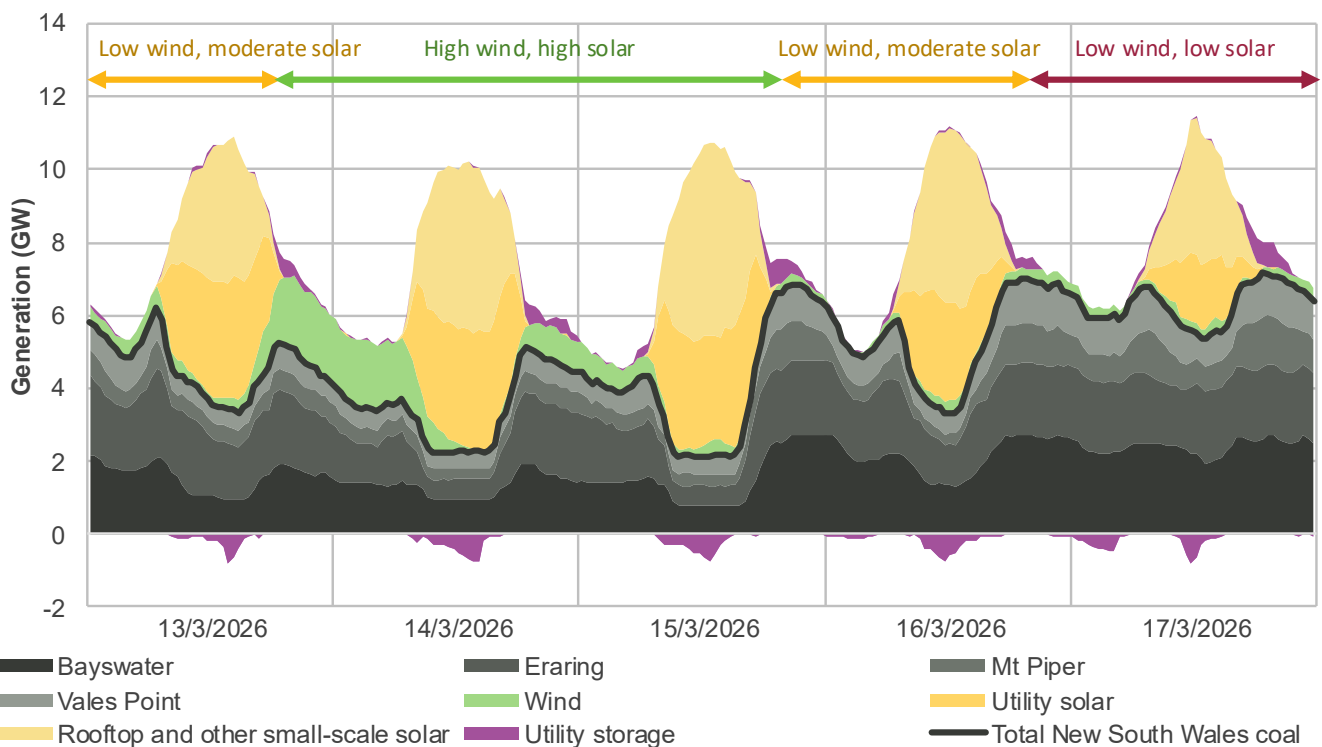
A4.4 Implications for coal operation during the transition

As the NEM transitions, VRE will become the primary source of generation and the demand profile will change as consumers continue to invest in CER and invest in increasingly efficient appliances, while businesses electrify and draw upon greater digital services. Section A4.3 discusses the increasing need for flexible generation to manage the variability of electricity generation and demand. The existing fleet of generators will also need to adapt to the changing generation landscape, particularly as the residual demand profile continues to reduce in the middle of the day while increasing during the evening peak as underlying electricity demand increases. This includes the remaining coal-fired generators, which have historically been operated with long periods of relatively stable output.

Some coal plant owners are already increasing the flexibility of their generation to better align with the availability of renewable energy. Owners are investing to keep their coal plants economic as renewables put downward pressure on wholesale prices. **Figure 7** shows a sample of recent coal generator behaviour in New South Wales during a period with a variety of renewable generation availability. Three operating profiles are highlighted that are influenced by the availability of VRE output, competing with coal operation for dispatch:

- During the period of **high wind and high solar** (marked by the green arrow), coal plants have the lowest market share, particularly when solar output is the highest during the middle of the day. Coal operation increases during the evening and overnight as solar output reduces.
- At the times of **low wind and moderate solar** (marked by the yellow arrow), coal plants also have reduced market share, but lower renewable output offers more generation opportunities for coal.
- When there is **low wind and low solar** (marked by the red arrow), coal plants observe relatively stable operations, as the lowest operating cost thermal generators in the NEM.

Figure 7 Actual coal generation compared to renewable energy generation and storage in New South Wales, March 2026 (GW)



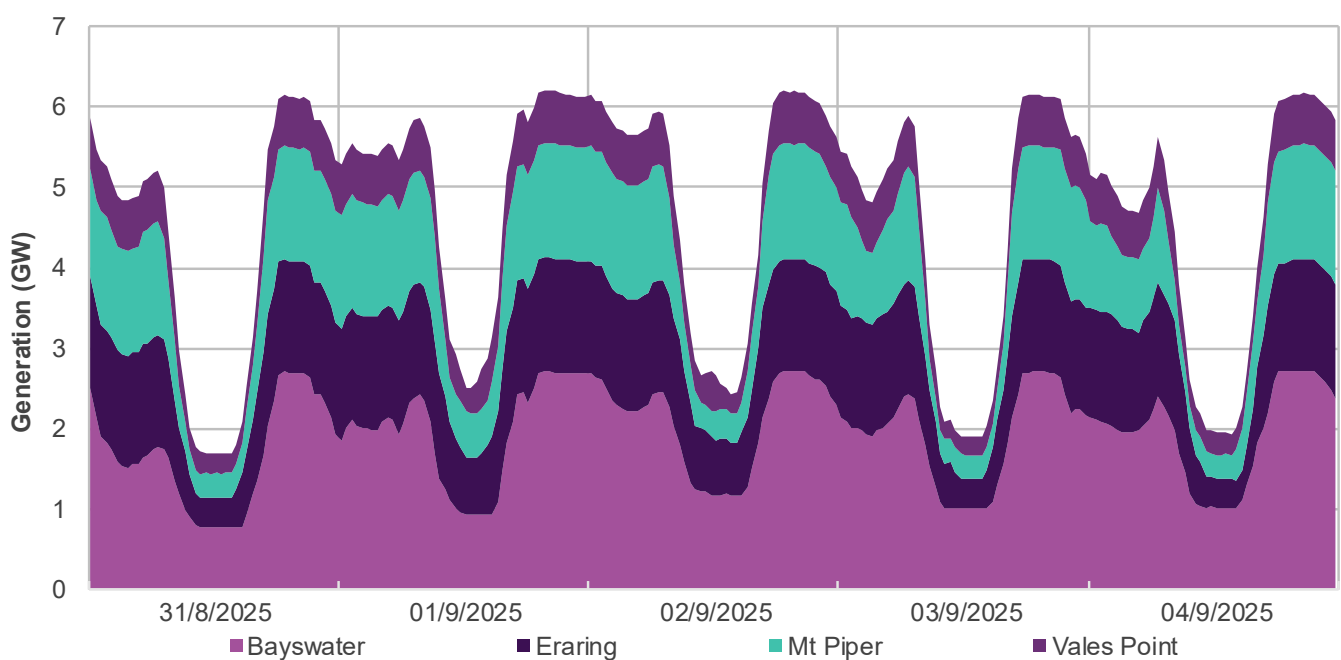


The need for coal to operate flexibility will continue to increase with greater levels of renewable energy penetration, and this flexibility is expected to be met through different operational and market strategies, subject to the technical limitations of each plant and complementing shaping assets such as storage.

Operating at minimum stable levels

One flexible operating strategy for coal plant operators is to reduce output to the minimum stable operating level of the plant during periods of high VRE generation and lower prices. **Figure 8** shows an example of recent coal behaviour in New South Wales, demonstrating how coal generators cycle between high levels of generation during the morning peak and reduce output to near minimum levels during daytime solar periods, before ramping back up for the evening peak.

Figure 8 Actual coal generation in New South Wales, September 2025 (GW)



With the increasing penetration of VRE, some coal-fired stations have reduced the minimum stable operating level in the last few years, increasing the range of operation of these plants. AEMO’s 2025 *Thermal Audit* report⁸ identified that coal plant operators across the NEM have conducted or are planning to conduct trials to identify how far minimum load operation could be reduced within the technical constraints of the station. The flexibility of the station to cycle between minimum stable operating levels and higher levels of generation is also limited by the ramping capability of the station.

The extent to which a coal unit will operate at or near its minimum stable operating level will also depend on the market conditions and the portfolio it supports. With increasing VRE penetration resulting in periods of no residual demand, the extent to which a portfolio can provide a corresponding load for its coal generation during those periods will influence the utilisation of minimum stable operating levels. Local storages, for example, can provide increasing controllable load during the middle of the day that can reduce the need for coal flexibility, by charging and absorbing coal output (and reducing the

⁸ See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf.



need for coal units to ramp up during peak demand periods, by discharging stored energy instead). Storages can therefore complement coal operation to smooth generation from coal-plants (as well as providing additional dispatchable capacity and storage capability of renewable generation).

Two-shifting

An alternative to operating at minimum stable operating levels through the daytime solar period is to stop generating completely through the middle of the day and then re-start for the evening. This is referred to as ‘two-shifting’. If a coal operator’s portfolio is unable to provide a covering load, two-shifting may be used to avoid generating during periods of negative price.

Some coal plants have trialled two-shifting, however utilisation in the NEM is expected to be limited due to the high cost, impact on plant life, and the technical feasibility for some stations⁹.

Economic withdrawals

Longer periods of coal units being withdrawn or decommitted, when not undergoing planned or unplanned maintenance, are referred to as ‘economic withdrawals’ or seasonal mothballing. In these circumstances, the unit is offline for commercial reasons, when the full capacity of the generator is not needed and it is more economic to have the unit unavailable in the market. These periods can be days, weeks, or months and may include the rotation of multiple units at a plant. During this period, an operator may have a relatively high lead time to return a unit to service if conditions change (while decommitted units may still be available to return to market participation, the plant may be cold and could take hours or days to bring back online, making it unavailable for security or reliability support within operational timeframes).

Economic withdrawals of individual coal units is expected to become a way for coal-plant operators to better match capacity requirements throughout the year. Residual demand is typically forecast to be higher during winter, due to increasing underlying heating load with electrification and reduced solar output. This predictability of seasonal energy requirements will allow coal plant operators the option of withdrawing units during summer when daytime prices are expected to be consistently lower and daytime flexibility requirements greatest, and then return them to operation during winter, though summer withdrawals may reduce the exposure of the stations to periods of high pricing during extreme summer demand conditions. Coal plant operators may also return decommitted units when VRE lulls are forecast, subject to the lead time that each unit and workforce has to return the unit to operating service.

Different strategies will be used to suit the conditions

The increase in CER and VRE generation will lead to an increasing number of days of low or no residual demand. It is expected that coal operators will employ a combination of strategies to operate coal-plants more flexibly and respond to changing market dynamics. **Figure 9** demonstrates the use of some of these strategies during different conditions:

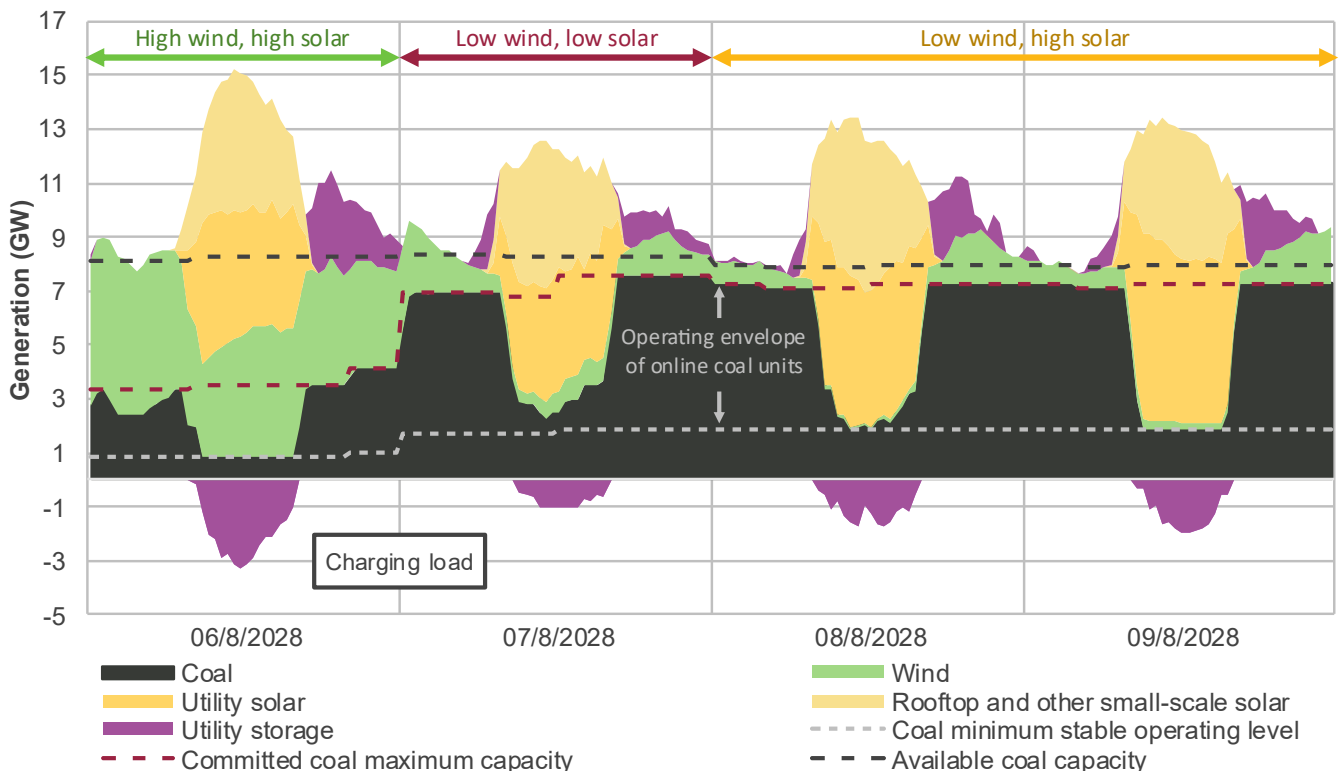
- During a period of **high renewable energy availability** (marked by the green arrow), several coal units are economically withdrawn due to sustained low residual demand.

⁹ Refer to the 2025 *Thermal Audit* report for further detail on two-shifting including the regional breakdown of operator expectations.



- As the **availability of wind generation decreases and reduced solar availability is forecast for the following day** (marked by the red arrow), the red dashed line shows how coal units are progressively committed overnight to support peak demands and coal output increases. As additional coal units are committed, the coal minimum stable operating level also increases.
- During the subsequent period of **low wind availability but increased solar availability** (marked by the yellow arrow), the coal generators utilise their minimum stable operating levels during the day and utility batteries charge at the same time.
 - The units that were returned from economic withdrawal at the start of this period remain committed, despite utilisation of minimum stable operating levels. The units are only expected to be withdrawn again once residual demand reduces to a level where the units will not be required for at least several days in a row. This will minimise unit start-ups and shut-downs, and the significant associated costs with those operations.

Figure 9 Forecast coal generation compared to renewable energy generation and storage in New South Wales, Step Change, 2028-29 (GW)

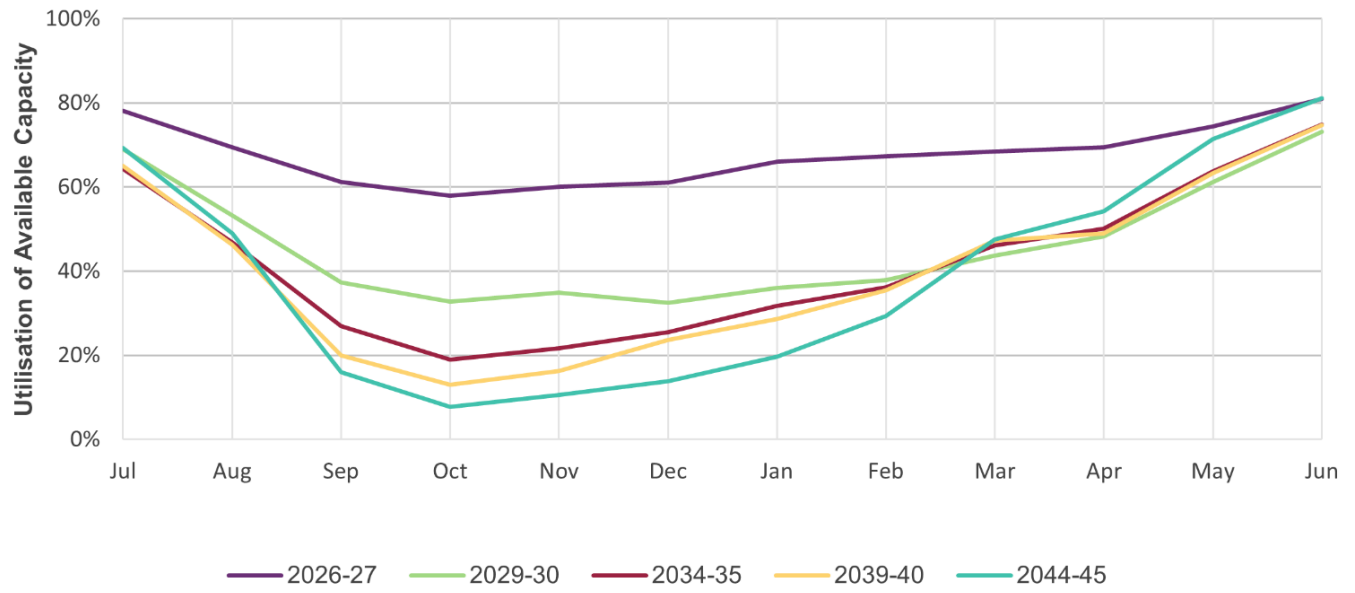


The shift to more flexible coal operations is expected to reduce the annual utilisation of the remaining coal stations across the horizon. Utilisation will remain high during periods when there is highest residual demand (from low VRE output), particularly during winter. **Figure 10** shows this seasonal trend, with the highest utilisation¹⁰ of the remaining coal fleet in the NEM occurring in the winter of each year.

¹⁰ Percentage utilisation is defined here as the energy generated over the amount of available generation, which excludes planned and unplanned outages.



Figure 10 Forecast monthly utilisation of coal generators, Step Change, 2026-27 to 2044-45





A4.5 VRE penetration and curtailment

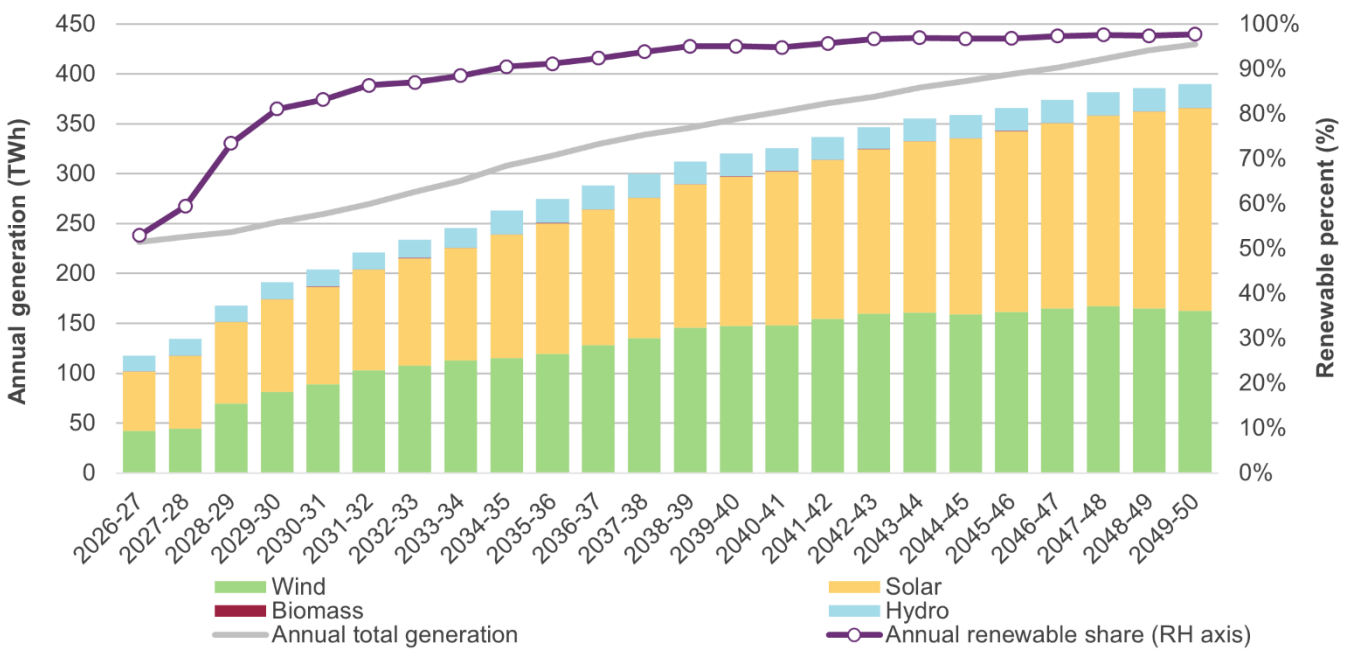
Replacing coal-fired generation with new forms of electricity generation, particularly VRE, as the dominant supply of electricity will need a diverse energy mix to ensure reliable supply. AEMO’s *Transition Plan for System Security*¹¹ details the plan for system security needs in the next 10 years to support the energy transition and operate a system with a large proportion of VRE, including large quantities of CER.

The changing technology mix and increasing decentralisation of the power system are introducing new operational challenges. Minimum operational demand is declining across all NEM mainland regions, driven by strong consumer uptake of rooftop and other small-scale solar. These conditions are increasingly creating periods of very low operational demand. During these periods, demand may need to be actively managed above minimum thresholds. This is required to maintain sufficient synchronous generation online to provide essential system services, such as system strength. Over time, the system will need to transition away from reliance on synchronous generation for these services. New technologies will play a critical role in delivering system security services that have traditionally been provided by fossil fuel generators.

Investments in storage will be essential in the future NEM to enable surplus VRE generation to be stored and allow this energy to be used when solar production drops later in the day or at another future time. Projected storage capacity is unlikely to be sufficiently sized or located to capture all VRE generation, so some generation will experience network curtailment when there are constraints in the network or there will be economic offloading when there is over-abundant renewable energy supply.

Figure 11 shows projected levels of annual total generation, annual renewable generation, and renewable share of total generation to 2049-50, including contribution from CER (aggregated within the Solar data series).

Figure 11 Projected annual NEM generation (TWh), annual renewable generation (TWh), annual renewable share of total generation, Step Change, 2026-27 to 2049-50



TWh: terawatt hours.

¹¹ At <https://www.aemo.com.au/energy-systems/major-publications/transition-plan-for-system-security-tpss>.



VRE penetration

The current record maximum renewable resource potential¹² in the NEM was set on 5 October 2025, reaching 113.9% of demand across a 30-minute period¹³. As renewable energy increases, the renewable resource potential in the NEM becomes higher and more concentrated, and greater than 100% renewable potential will occur more frequently at increasingly higher underlying demand levels. **Figure 12** shows the projected changes to renewable resource potential relative to underlying demand from 2026-27 to 2049-50 in *Step Change*.

Periods where there is greater than 100% renewable resource potential will not necessarily result in 100% instantaneous renewable penetration. Instantaneous renewable penetration levels are restricted by market behaviours, network constraints, and system security requirements. Records for instantaneous renewable penetration, or share of total energy supplied from renewable sources, have already surpassed 77.2%¹³, and reached 78.6% for a half-hour on 11 October 2025.

Figure 12 Projected renewable resource potential, *Step Change*, 2026-27 to 2049-50 (GW)

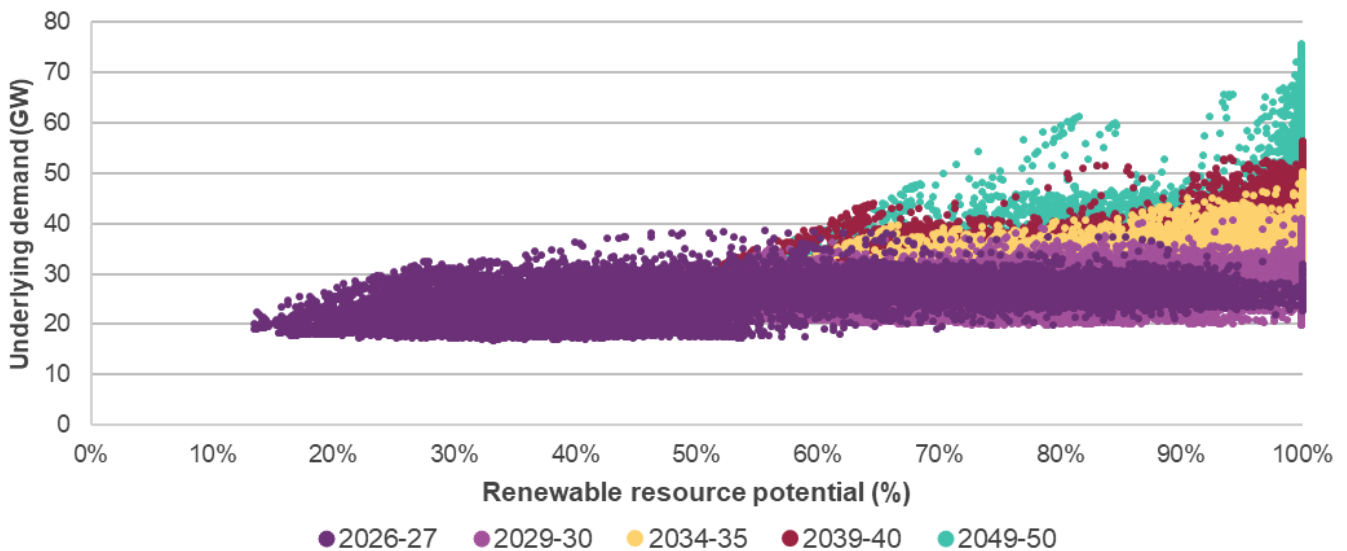


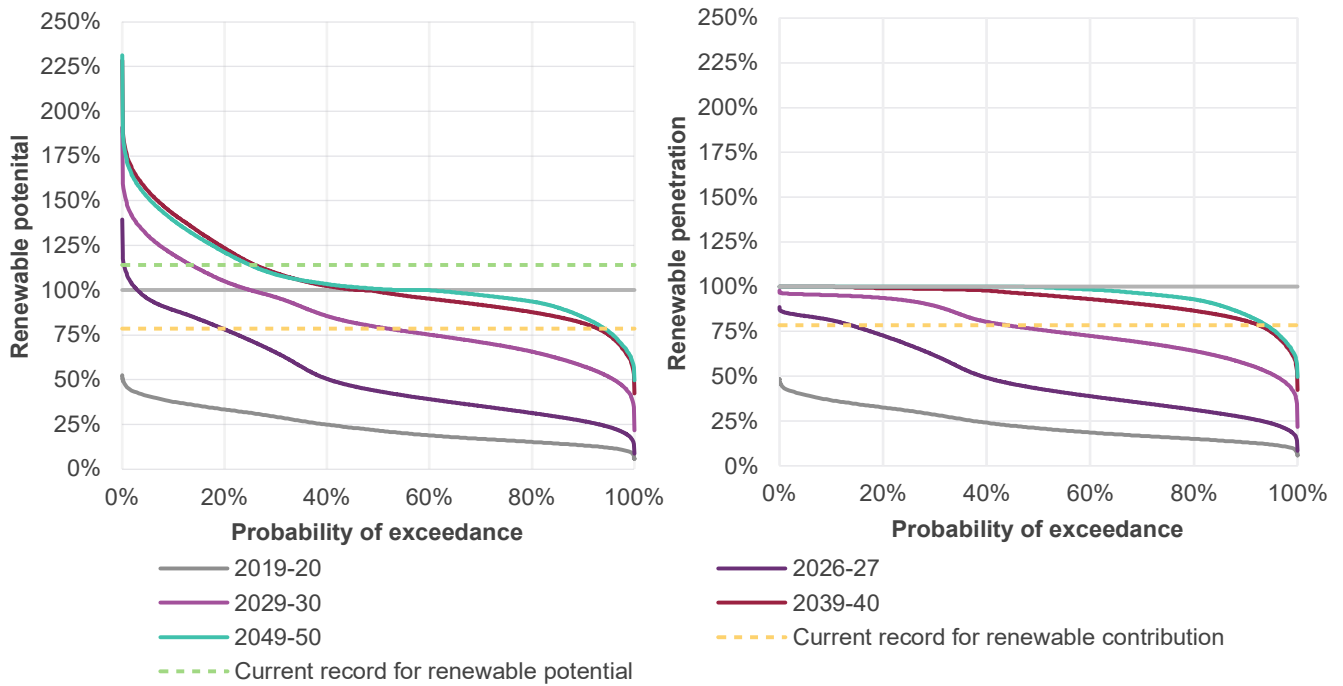
Figure 13 shows the distribution of renewable resource potential and penetration for every half-hour in 2019-20 (historical) and in forecast years 2026-27, 2029-30, 2039-40 and 2049-50, as well as the current NEM-wide records for instantaneous potential and penetration. Renewable resource potential is projected to be sufficient to meet all demand occasionally from the start of the modelling horizon, and around 25% of the time in 2029-30.

¹² Renewable resource potential is defined as total available power from CER and utility-scale VRE, even if not necessarily dispatched, plus actual generation from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

¹³ See AEMO *Quarterly Energy Dynamics* Q4 2025, at <https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q4-2025.pdf>.



Figure 13 Distribution of actual and projected renewable potential (left) and penetration (right), including current NEM records for instantaneous renewable potential and penetration, *Step Change*, 2019-20 (actual), 2026-27 to 2049-50 (projected)



Geographical diversity of VRE resources is delivered through developing new resources across the NEM, many of which will be within new REZs, and connecting these new developments with customers and storages across the grid through network expansion. As a result, renewable resource potential is projected to rise across nearly all half-hour periods during the year. Increased use of storage technologies will help shift excess daytime generation from periods of renewable energy surplus to times of lower VRE availability, which will rely on appropriate storage management and storage depth to achieve this.

System security requirements will limit maximum VRE penetration

The highest levels of instantaneous penetration of VRE will be limited by the availability of sufficient power system services to maintain security of supply. During low load conditions, AEMO may set minimum system load (MSL) thresholds, which are determined by the minimum combination of thermal units that need to remain online to provide system security services. These thresholds change dynamically depending on real-time system conditions. Over time, MSL thresholds will decrease as system security parameters are decoupled from synchronous fossil fuel generating units and these services are delivered by alternative technologies.

VRE curtailment

The 2026 ISP identifies frequent instances where VRE generators will not be able to operate to their maximum potential, either due to:

- periods when VRE resource potential exceeds demand (including the additional capacity to store excess generation), particularly at times of low operational demand,
- insufficient transmission capacity to transport VRE to demand centres, or



- system security requirements that require synchronous generation to be dispatched to maintain a secure power system (until such time as alternative technologies can provide these critical services).

These conditions may lead to economic offloading of energy when generators reduce output due to low market prices or lack of available demand, or to network curtailment where insufficient transmission capacity exists for generators to continue to operate.

The 2026 ISP projects that it is uneconomic to develop sufficient network and/or storage capacity to accommodate all peak VRE generation potential, meaning some degree of economic offloading or network curtailment is inevitable to keep total system costs as low as possible. As the seasonal load profiles diverge, generation is increasingly needing to be developed to meet the energy consumption requirements of winter when consumption is high and VRE production is reduced, and therefore summer periods may exhibit increased periods of economic offloading or network curtailment when renewable resources are higher.

Hydrogen electrolyser developments in the ODP are projected to play a role in reducing curtailment by absorbing excess VRE generation. Electrolysers co-located with renewable generation developments may reduce network curtailment by accessing renewable energy generation before network limitations.

Figure 14 shows the total VRE potential that is projected to be utilised (generation) or not (economic offloading and network curtailment) out to 2049-50 in the ODP. As coal generators close and transmission is expanded, the NEM-wide level of available VRE curtailed annually is projected to remain below 20% across the horizon, although VRE in some REZs may be constrained significantly more than the NEM-wide average. See Appendix A3 Renewable Energy Zones for VRE curtailment projections within each REZ. The majority of unused VRE potential is the result of economic offloading, rather than network curtailment due to transmission limits.

Figure 14 Projected NEM-wide VRE generation, economic offloading and network curtailed energy, Step Change, 2026-27 to 2049-50 (TWh)

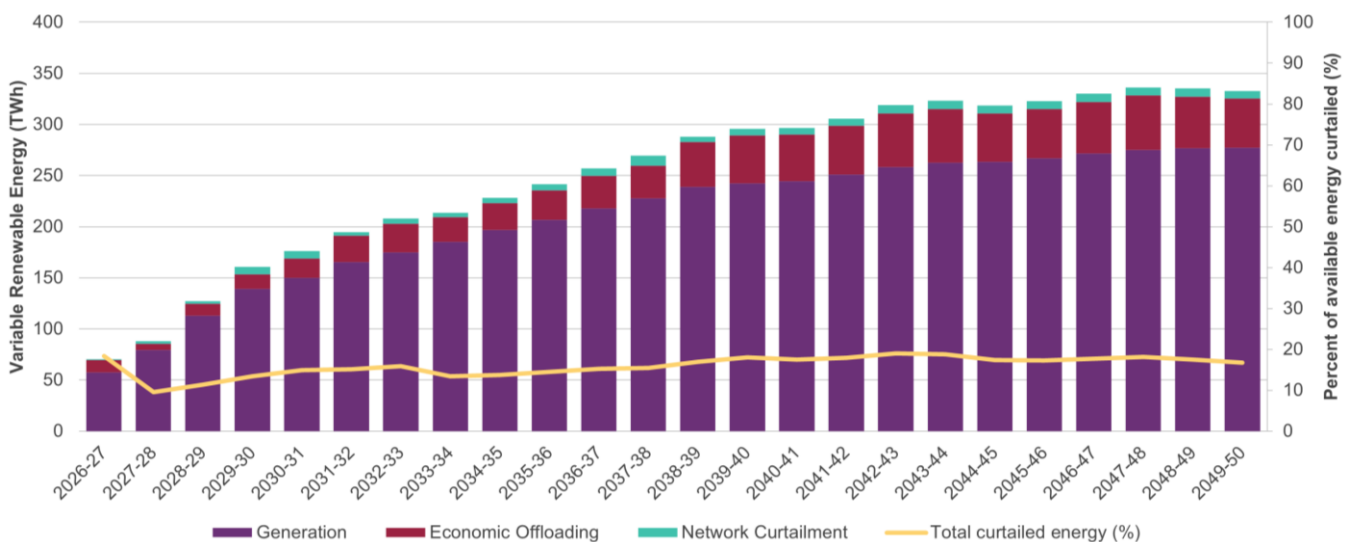


Figure 15 shows the breakdown of projected curtailed energy by technology type. Solar generation is projected to experience a higher degree of economic offloading, particularly on sunny days in summer months when there is abundant solar generation and negative residual demand, and not enough storage capacity to capture it. Wind generation exhibits more variable and less correlated output between sites, resulting in comparatively lower curtailment.



Figure 15 Projected NEM-wide unutilised VRE potential, broken down by technology type, Step Change, 2026-27 to 2049-50 (TWh)

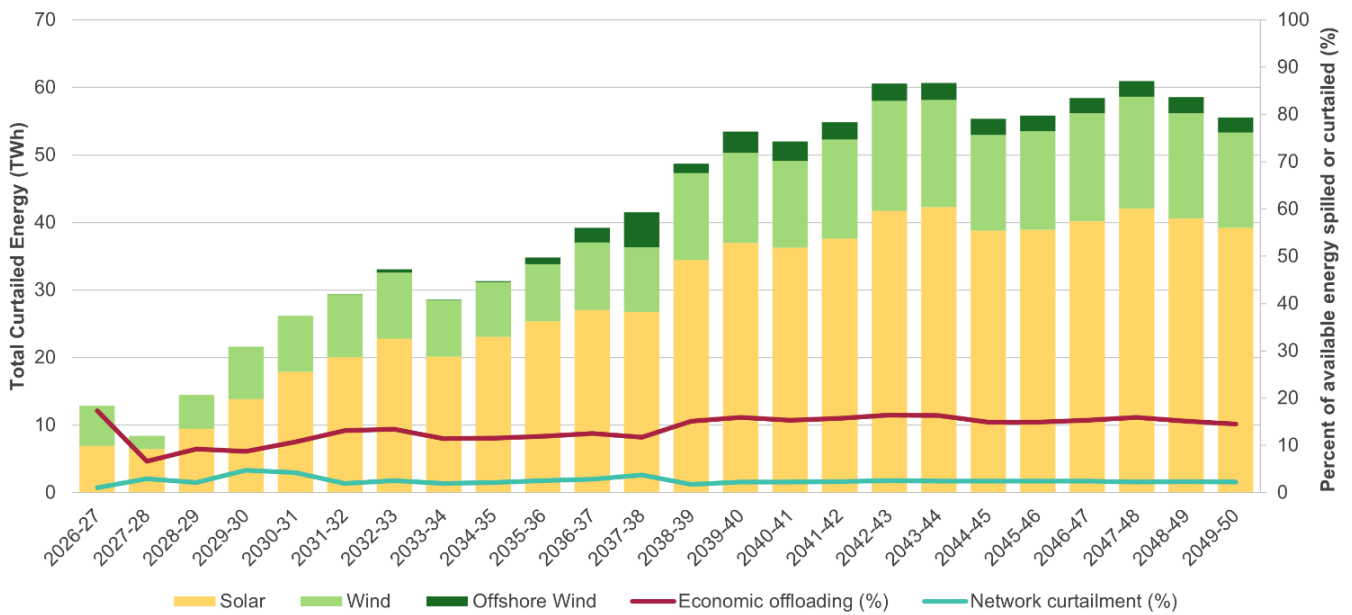
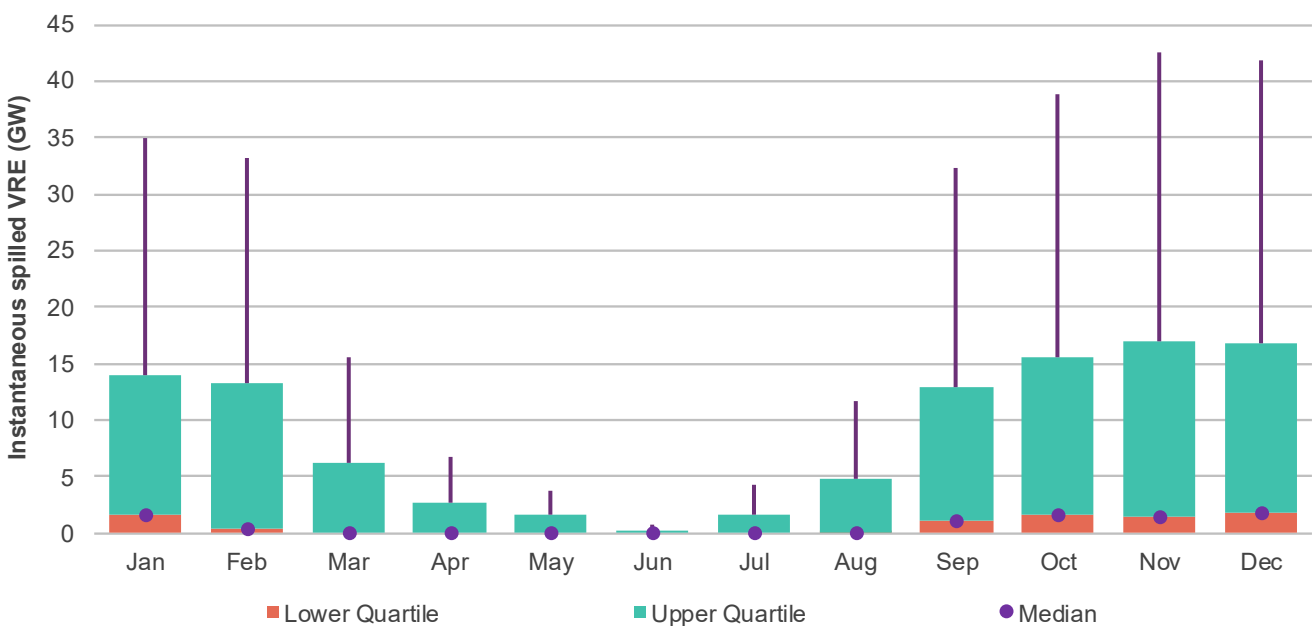


Figure 16 shows the projected monthly distribution of instantaneous economic offloading in 2039-40 across a range of weather reference years, and illustrates the months with excess renewable generation potential. The large majority of economic offloading is projected to occur during daylight hours on sunny and windy days, particularly in summer months more than in winter. The seasonal trend of VRE economic offloading indicates the role long-duration storages could have in firming energy on a seasonal basis, particularly if hydrogen electrolyser loads do not emerge as anticipated in the 2026 ISP scenarios.

Figure 16 Projected NEM capacity of VRE subject to economic offloading, Step Change, 2039-40 (GW)





A4.6 Storage technologies will firm renewables by firming energy

Storages in the NEM currently play several roles including providing energy firming, system balancing and active power reserves, in addition to advanced power system services such as synthetic inertia and system strength support (by providing a stable voltage waveform). Though storages will continue to provide system security services, storage operators are expected to rely less on system services revenue and increasingly develop their operational strategies around energy arbitrage. As VRE penetration increases, larger quantities of all forms of storage will be required across the NEM to accommodate the peaks and troughs in renewable generation and match energy supply to demand.

The 2026 ISP projects the storage capacities needed to firm the NEM's VRE developments. The development of medium and deep storage technologies is important to complement flexible gas and hydro generators, providing the capacity to store energy and dispatch it over long periods.

Storage definitions used in this appendix

- **CER storage** – behind-the-meter household and business storage, including EVs that may be able to send electricity back into the grid. Coordinated CER storage is managed as part of a VPP (enabling a response to market signals); passive CER storage is not, operating to service the household's needs in isolation.
- **Shallow storage** – utility storage, connected to either the transmission or distribution network, to dispatch electricity for less than four hours, valued for both its provision of system services and stored energy.
- **Medium storage** – utility storage with the capability to dispatch electricity for four to 12 hours. This includes batteries and pumped hydro (or other emerging technologies in future) which can shift large quantities of electricity to meet evening or morning peaks.
- **Deep storage** – utility storage that can dispatch electricity for more than 12 hours, to shift energy over weeks or months (seasonal firming) or cover periods of low sunlight and wind (renewable lulls), backed up by flexible gas.

Intra-day storage

The NEM will increasingly rely on all forms of storage to shift available energy supply within a 24-hour period to match instantaneous demand. Shallow and medium storages will provide much of this function, acting as a natural complement to solar generation, with daily shifting of surplus daytime VRE generation to meet evening peak demand and overnight surplus wind energy stored to meet morning peak demand. As already discussed, future operational strategies for storages are also expected to include the use of storage to create a corresponding load, through battery charging or pumping of water, for thermal generators operating near minimum stable levels during periods of low system demand.

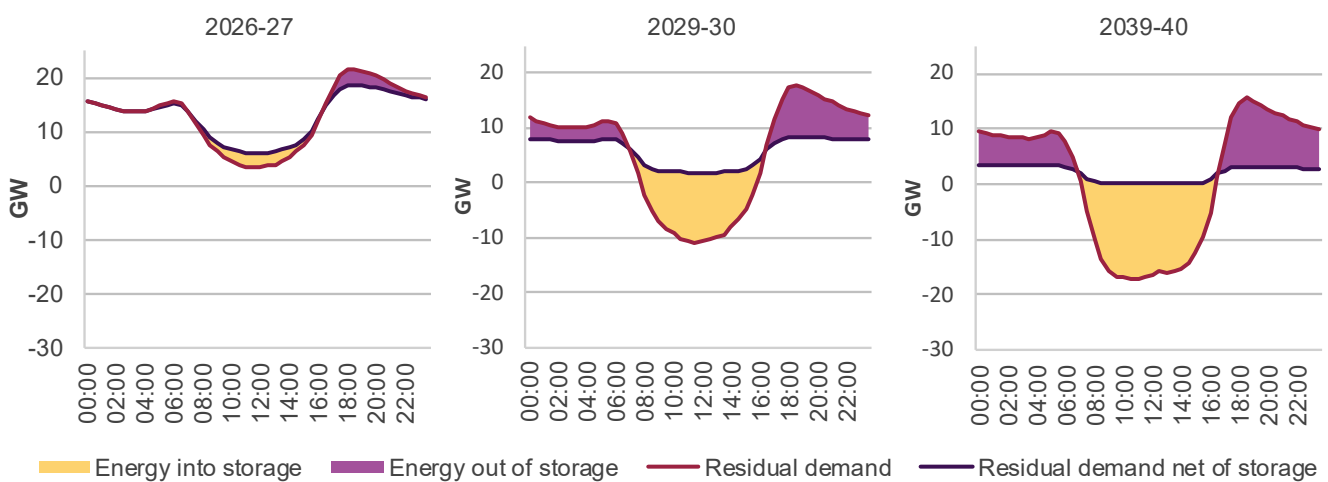
Storages will typically charge when low-cost, surplus daytime VRE is plentiful, and store and discharge that energy when prices are higher during peak demand periods. This reduces dependence on traditional peaking technologies such as flexible gas. In some instances, operating hydro and gas generators to pre-charge shallow and medium storages can be an effective strategy to improve the reliability of supply, provided these lulls can be anticipated in advance, although this would impact overall emissions outcomes, and would need high prices to compensate for charging from gas generation during periods of VRE scarcity.

Figure 17 shows the projected evolution of time-of-day average profiles of residual demand and the growing impacts of storage technology. As the penetration of VRE increases, coal-fired generators retire and more storage capacity is



developed, the daytime residual demand is projected to decrease and feature deeper troughs. Storages will enable greater volumes of surplus energy to be time-shifted to service evening demand peaks. Storages will also help smooth the evening residual demand peak, allowing generators with less flexibility to operate at a flatter profile. As the penetration of VRE increases across the ISP horizon, periods of negative residual demand net of storage (as indicated in the figure) are still expected to occur during the middle of the day. This indicates that not all the VRE generation can either serve prevailing customer load or be stored, leading to some economic offloading or network curtailment. These outcomes are driven by market dynamics and system conditions, such as a finite amount of storage capacity and network constraints, that limit the ability to capture all excess generation.

Figure 17 Projected time-of-day average profile of residual demand, *Step Change*, 2026-27, 2029-30 and 2039-40 (GW)



Intra-week storages balance short-term VRE variability

Longer duration storage, including medium and deep storages, play a critical role in smoothing out larger variations in VRE generation over multiple days. The depth of these facilities, in conjunction with the operational forecasting capabilities of AEMO, weather forecast providers and storage operators, is critical for storing available energy production ahead of sustained periods of low VRE output with relatively short notice.

To maximise the reliability of the power system, deep storage operators may need to store several days' worth of energy, including using thermal and hydro generation if available, ahead of periods of low forecast VRE potential to ensure sufficient dispatch capacity (and energy) is available during protracted periods of extremely low VRE. This will enable improved reliability outcomes during sustained low VRE output (see Section A4.7).

Long duration storages provide seasonal firming

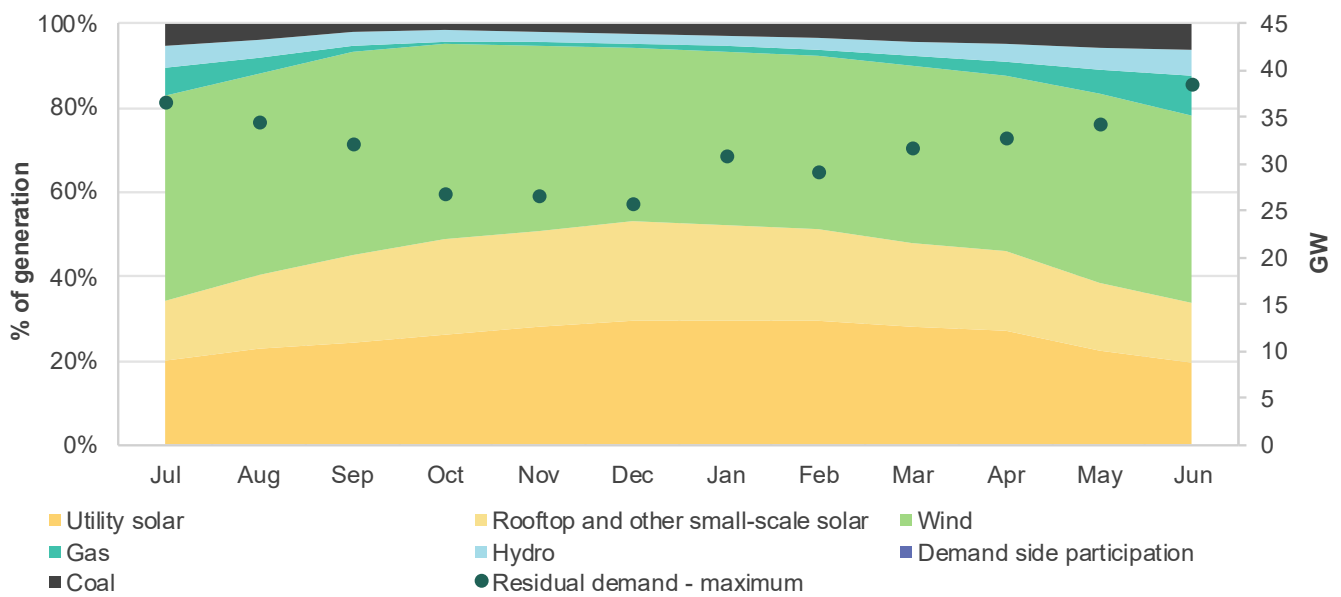
Deep storage is critical in enabling the shifting of surplus VRE generation between seasons and providing resilience for longer periods of sustained low VRE generation. This is increasingly important as coal generators retire. **Figure 18** shows the generation share by technology that is either used, or shifted, each month. It includes all relevant technologies that produce electricity, and excludes storage operation that shifts surplus generation. The figure shows that the projected monthly generation mix and maximum instantaneous residual demand in 2039-40 has strong seasonal dependence:

- Solar output is higher on longer bright summer days with seasonality most prominent in southern regions.



- Wind output is greater on average during winter months but typically has greater volatility, particularly in early winter.
- Residual demand is higher during winter, due to higher underlying heating load and reduced solar output.
- Operation of seasonal energy storages, hydro generators with access to deep water reservoirs, and flexible and mid-merit gas are projected to become increasingly important during winter to support lower solar output and more volatile wind output. All storages will also have a critical contribution during extreme demand days in summer, especially in earlier years when the coordination of CER is projected to be more limited.
- Available coal and gas generation may operate throughout the year, but higher output is important during winter months to complement VRE and storage¹⁴.

Figure 18 Generation mix and maximum monthly residual demand (GW), Step Change, 2039-40



The NEM currently relies on deep water reservoirs to store energy season-to-season, with water outflows balanced between generation needs and water licence release requirements, depending on the reservoir. The type of reservoir, water release requirements, and whether the water stored is used for other purposes will influence the role that hydro generation can play in storing energy. **Figure 19** shows how deep storages are projected to shift energy between seasons, using Snowy 2.0 as an example, with stored water levels steadily increasing in spring and summer when renewable availability is greatest and then discharging in late autumn and winter as needed.

¹⁴ See Appendix A10 Gas Development Projections for more information on the gas supply, infrastructure and storage requirements to meet NEM needs.



Figure 19 Projected water levels in Snowy 2.0 over a year, Step Change, 2029-30 to 2049-50 (gigawatt hours [GWh])

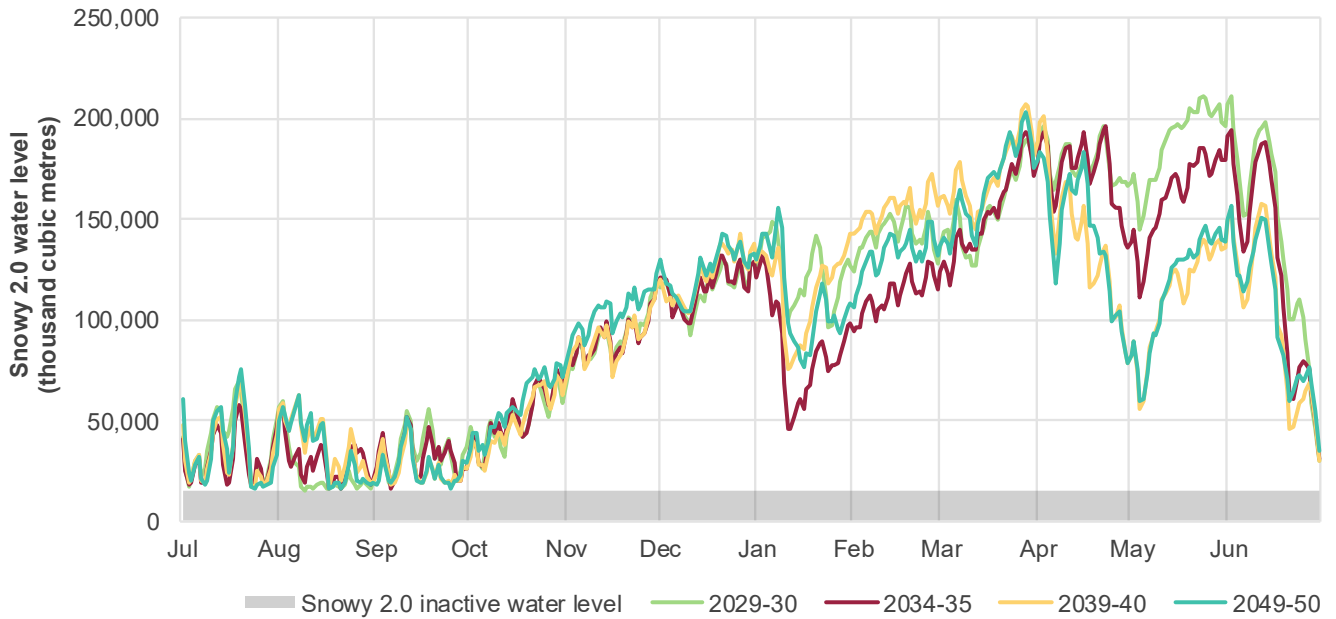
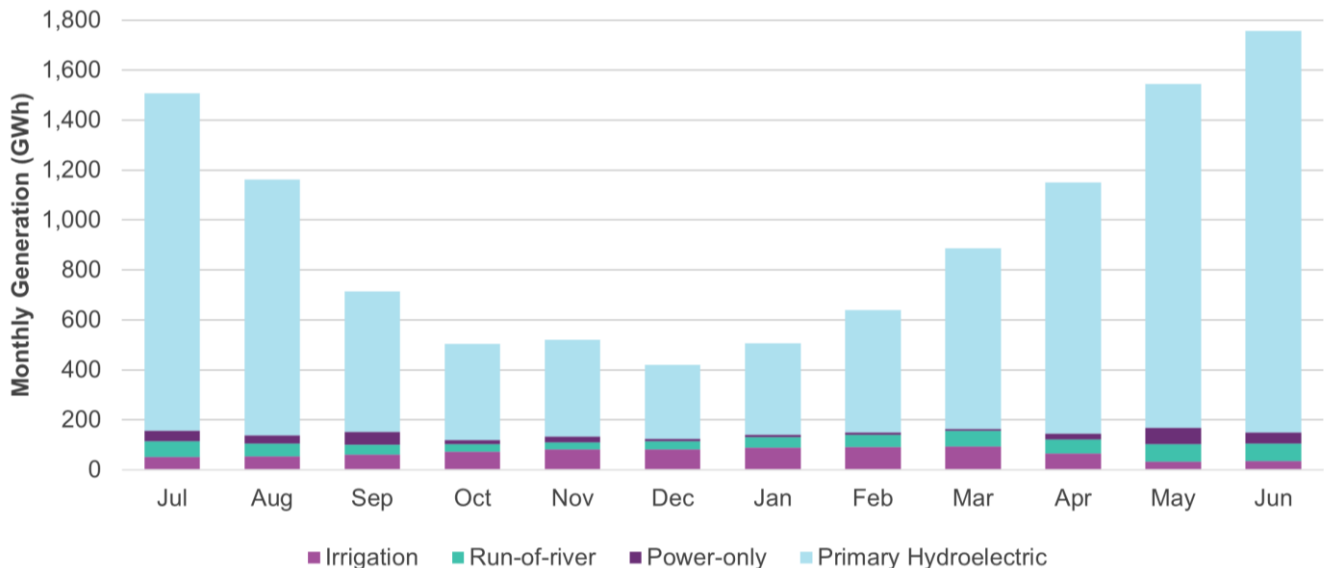


Figure 20 demonstrates how hydro generators that can prioritise electricity generation, and have sufficient storage to provide seasonal flexibility, produce more energy in winter when residual demand is highest due to lower solar output and higher underlying load. This includes primary hydroelectric and power-only generators¹⁵, which are hydro schemes where the storage and release of water is primarily or exclusively used by the hydro scheme operator for power generation.

Figure 20 Forecast monthly hydro generation by hydro scheme type, 2039-40, Step Change (GWh)



¹⁵ The different types of hydro scheme categories are defined in the 2025 IASR, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios>.



In contrast, hydro generators that also interact with customers that use the available water for irrigation purposes, and run-of-river generators that have little seasonal storage, generate more frequently in summer, when irrigation requirements are the highest, even though this is when residual electricity demand is lower. For some hydro generators, environmental release requirements also play an important role, requiring operators to balance generation decisions with downstream river flow requirements.

Deeper storages are expected to become more prominent in the NEM. This shift is already evident in the connections pipeline, with a trend away from shallow and towards medium and longer-duration storage. The ISP similarly indicates that medium duration storage or deeper will be the more prominent utility-scale solution, with shallow solutions primarily provided by CER. As the system evolves, reliability risks are expected to shift from shortfalls in instantaneous generation capacity toward greater energy adequacy challenges. In this context, deeper storage will play an increasingly important role in maintaining system reliability.

Impact of imperfect foresight of battery operation

Storage operators must conduct charging and discharging activities with imperfect foresight for the expected market conditions each day. AEMO's market modelling includes different levels of foresight to enable efficient utilisation of energy storages, while attempting to reduce the degree of storage management perfection that can apply in simulation models.

To reduce the management performance of stored energy in the ISP models, AEMO has introduced a margin of energy at the upper and lower states of charge that is accessible to the system only during conditions that would otherwise result in unserved energy (USE) (effectively creating buffers that reduces the storage depth of typical operating conditions)¹⁶. These buffers act as a proxy for operational risk mitigation strategies, preserving the option for storage devices to respond flexibly – either charging or discharging – should unforeseen events arise. This approach restricts storage devices from using its full capacity of stored energy on a daily basis¹⁷.

Assessing the impact of reduced foresight in the operation of battery storage

AEMO has analysed scenarios in which a reduced look-ahead horizon is applied to assess system operability under conditions where there is increased forecast uncertainty. In this approach, storages plan their state of charge with a reduced level of foresight, and therefore optimise their operation around meeting short-term objectives, with less capability to prepare for potential energy shortfalls in the days ahead.

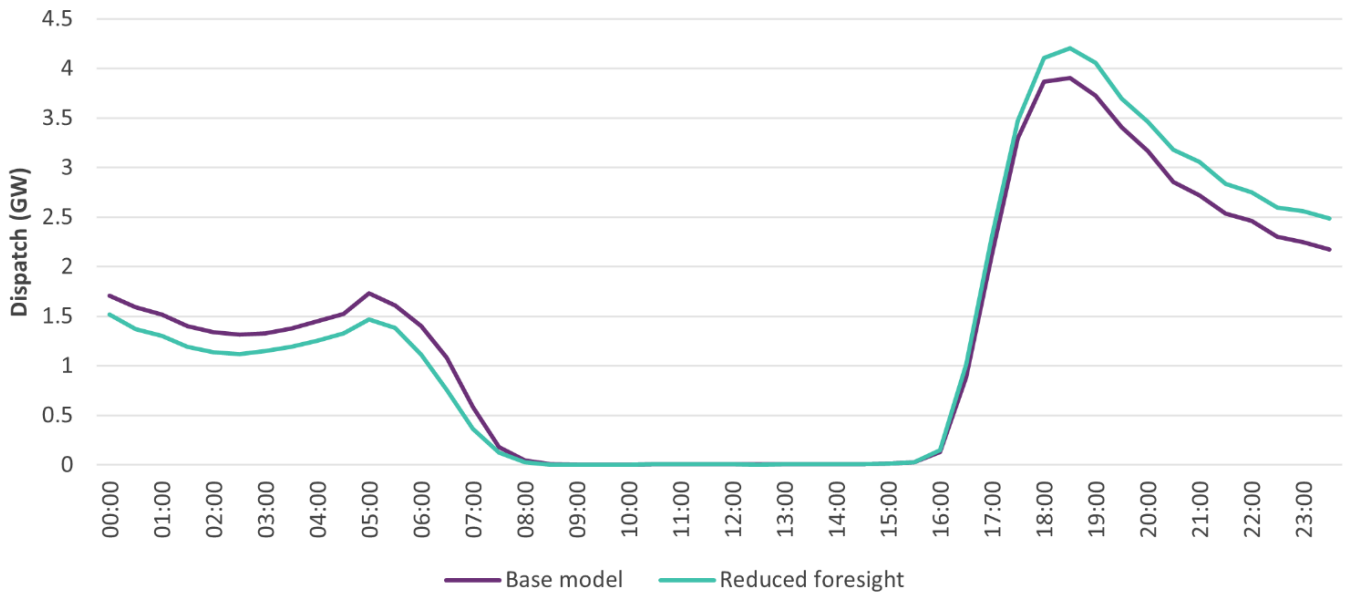
Figure 21 compares the modelled dispatch profile of shallow and medium storage from the base operability model against the profile of storages operating with a reduced look-ahead during 2039-40. The lack of foresight introduced by implementing this approach increases the amount of energy dispatched during the evening peak, as storages respond to the immediate demand need and price signals, rather than saving the energy for overnight and into the next day. This can lead to greater risk that storages are unable to fully charge the next day if VRE output is relatively low, and means they could be exhausted earlier than desirable when supporting the next day's evening peak.

¹⁶ For more detail on the limitations on storage devices that AEMO has applied, see the *ISP Methodology*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

¹⁷ The headroom and footroom reservation were implemented as soft constraints, with the cost of violation priced below the market price cap, to enable discharge if required to avoid a low energy reserve outcome.



Figure 21 Impact of reduced foresight on the average hourly dispatch profile of shallow and medium energy storage, Step Change, 2039-40 (GW)





A4.7 Operating the power system during long dark and still conditions

The NEM must be resilient in its capability to provide energy in all conditions, including when there is minimal or no sunshine or wind for prolonged periods. The ODP provides resilience during long dark and still periods through a geographically and technologically diverse mix of VRE generation, supported by hydro and flexible gas generation, demand side response, and storages of various depths. Transmission augmentations enable the transport of electricity from regions with excess generation to regions experiencing tighter VRE supply conditions.

VRE lulls are defined in this analysis as multi-day events where availability from wind and solar generation across the NEM is sustained below the fifth percentile of recently observed weather history¹⁸.

The timing, severity and duration of prolonged dark and still weather conditions over a wide area are difficult to predict. AEMO applies historical 'reference years' in the ISP modelling to capture the impact of weather conditions on the power system, in different locations and across all times of the day and year. AEMO's modelling leverages 15 years of observed weather patterns (from 2011 to 2025), providing a diverse mix of weather conditions (including recent years with VRE lulls such as in May and June 2024 and in June 2025), but the future may provide more extreme conditions than have been observed in this period. Climate analysis undertaken by Risk Frontiers¹⁹ projects that to 2090 the average duration and frequency of solar lulls across the NEM is expected to decrease, while the frequency and average duration of wind lulls is projected to remain relatively consistent with observed history.

Definitions relevant to VRE lulls used in this appendix

- **Available capacity factor** – the percentage of a given generator or group of generators available to generate for a given period, relative to its maximum generation capacity. For example, a wind farm with a maximum capacity of 100 megawatts (MW) that is currently available to generate 50 MW has a capacity factor of 50%. If the same wind farm is available to generate 800 megawatt hours (MWh) in a day, its daily available capacity factor would be 33.33%, given it could produce 100 MW for 24 hrs, or 2,400 MWh if at full output for the day. Available capacity factor measures availability only without considering economic offloading or network curtailment.
- **VRE lull** – where the daily available capacity factor of all relevant VRE does not exceed the fifth percentile for at least three consecutive days. For example, if the fifth percentile for VRE was at 20%, any three consecutive days with a daily capacity factor lower than this is considered a VRE lull. A VRE lull can be defined for a specific sub-region, a region, or the entire NEM. In this analysis, a VRE lull is defined across the NEM, or for southern mainland regions when specified.

¹⁸ This definition is closely aligned with the VRE lulls definition from analysis undertaken by Risk Frontiers for ASL (in its capacity as NSW Consumer Trustee under the NSW *Electricity Infrastructure Investment Act 2020*) to use in the 2025 *Infrastructure Investment Objectives* report. Refer to *Impact of climate change on VRE lulls*, at https://asl.org.au/-/media/services/files/publications/iio-report/2025/250813-impact-of-climate-change-on-vre-lulls-report-by-risk-frontiers.pdf?rev=c62f4f6a7912476593a834d01e71fab3&sc_lang=en.

¹⁹ Undertaken by Risk Frontiers for ASL to use in the 2025 *Infrastructure Investment Objectives* report.



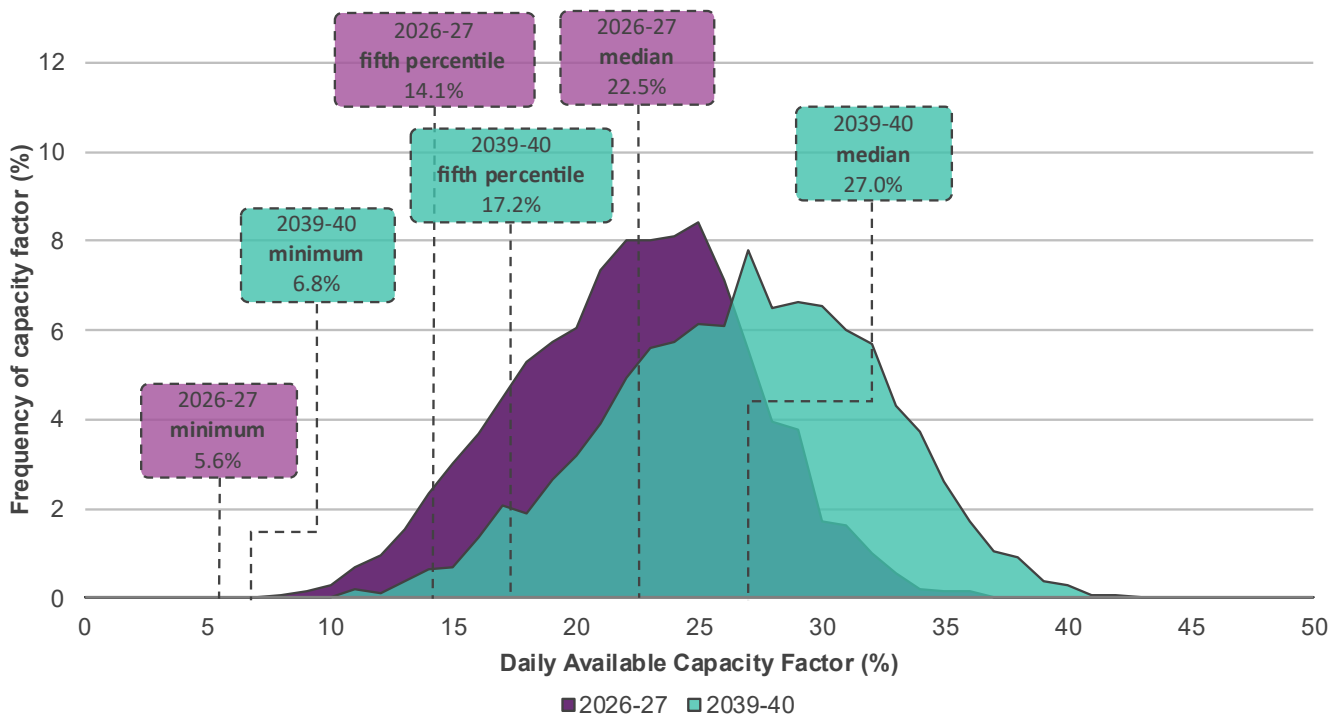
Diversity of the renewable generation mix provides resilience for the NEM

Long dark and still conditions typically can last for hours or a whole day and are problematic for system operability when they persist for multiple days. These weather conditions are most likely to occur during winter and cause longer VRE lulls when lower solar generation coincides with still wind conditions.

In a system with a high proportion of VRE, the resulting energy shortage may cause reliability risks if sufficient firming resources are not available for dispatch, or if fuel supplies (such as gas or diesel) are not adequately available to enable flexible gas operation for sustained duration. Delivering geographical diversity of generation and firming resources is a strong benefit of the network developments in the ODP to improve the power system’s resilience to weather variability.

Figure 22 shows the spread of daily available capacity factors that are forecast for VRE across the NEM in 2026-27 and 2039-40, indicating that the capacity factors for VRE will increase in the future as more geographical diversity is introduced, and new VRE developments connect at locations of high resource. Furthermore, wind turbines are expected to develop with longer blades, higher hub heights, and generally assumed to be increasingly efficient and effective over more diverse wind speeds than older wind turbines. The development of offshore wind resources, with the generally higher output that this technology provides relative to onshore alternatives, also helps to increase capacity factors.

Figure 22 Forecast frequency of VRE daily available capacity factors across the NEM with minimum, fifth percentile and median capacity factor, across all reference years, 2026-27 and 2039-40



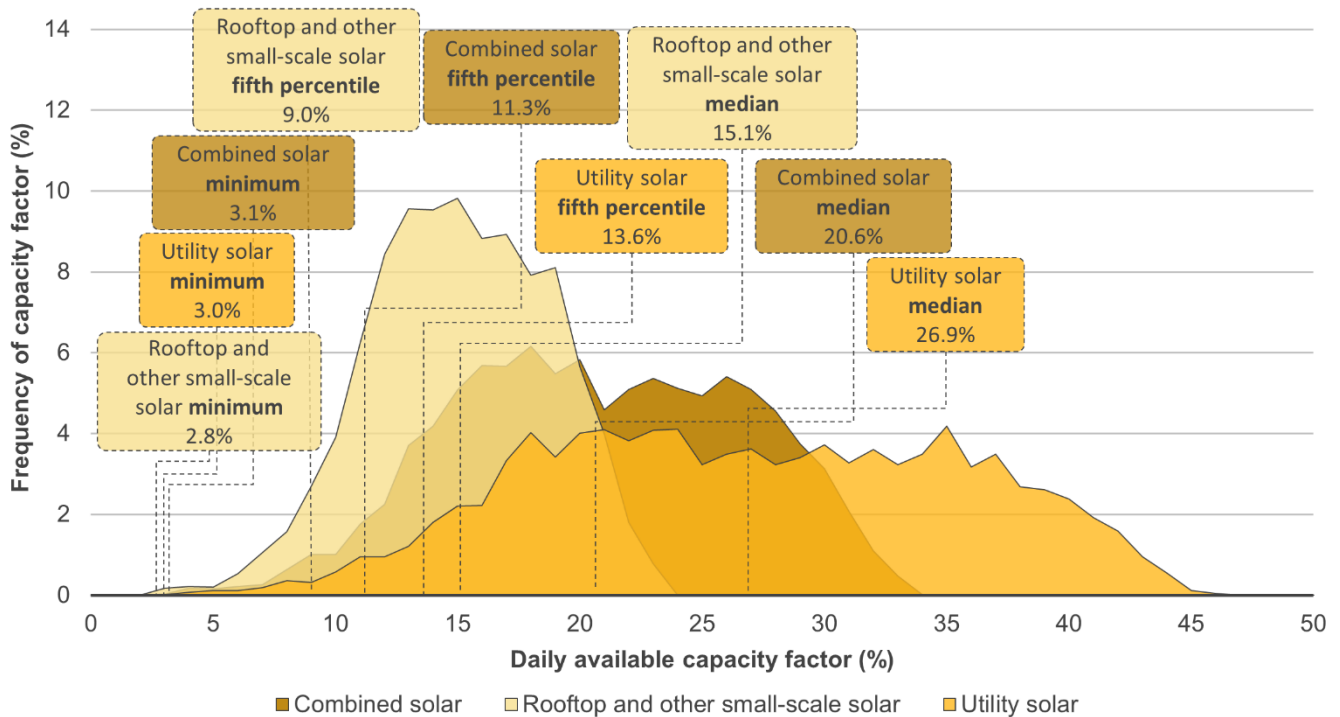
Note: Available capacity factor measures availability only without considering economic offloading or network curtailment.



For solar generators, utility-scale developments will have materially higher capacity factors than rooftop and other small-scale solar (see **Figure 23**), as they are designed and developed to harness more solar energy, using technologies such as single-axis tracking to follow the sun’s direction, improving panel efficiency, and are less impacted by shading from trees and surrounding buildings.

The generation mix for utility-scale devices also tends to be more geographically diverse than rooftop and other small-scale solar, which is an important driver of weather resilience. Solar developments at lower latitudes (closer to the equator) also receive more consistent sunlight across the year, meaning that NEM-wide solar aggregate capacity factors will be influenced by the geographical location of new developments.

Figure 23 Forecast distribution of total solar, rooftop and other small-scale solar, and utility solar daily available capacity factors across the NEM with minimum, fifth percentile and median capacity factor, across all reference years, 2039-40

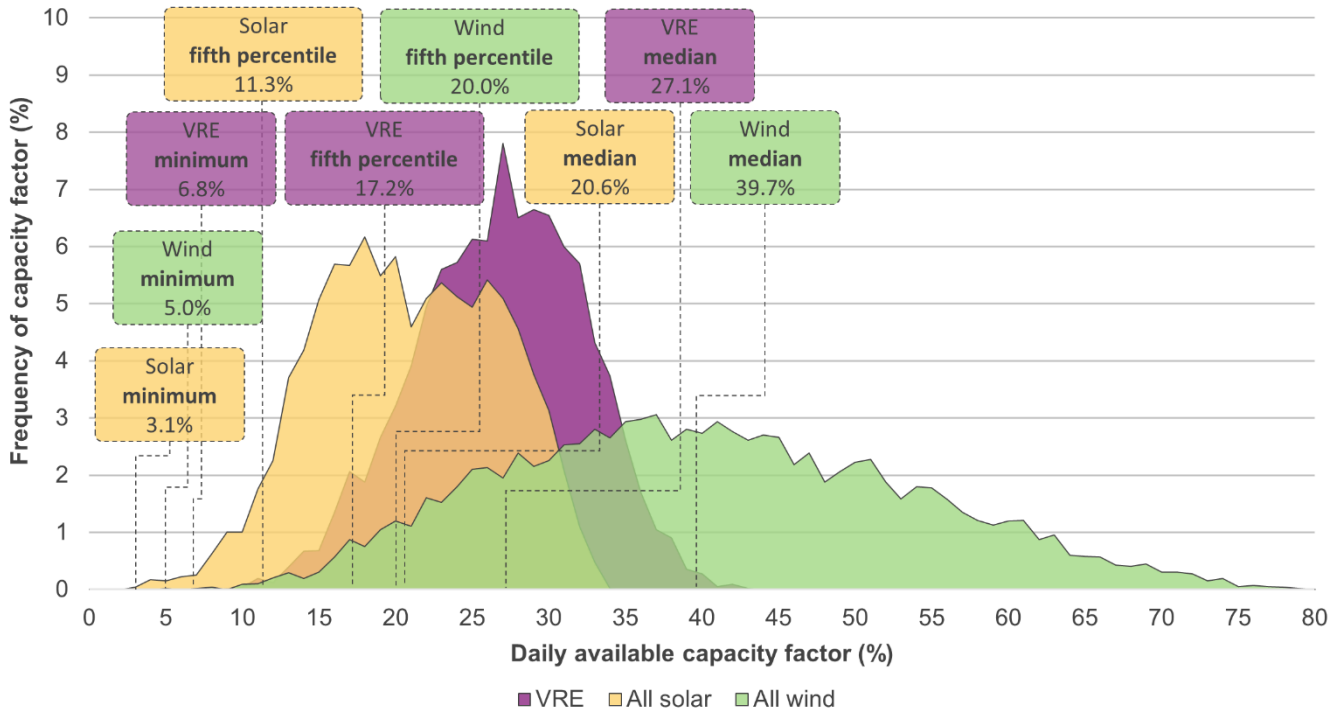


Note: Available capacity factor measures availability only without considering economic offloading or network curtailment. The analysis applies the projected geographical distribution of these technologies, across regions and REZs in the ODP, and therefore is not a generic estimate of any solar farm at any location.



Diversity of renewable energy technologies provides resilience through different weather conditions. **Figure 24** demonstrates the aggregate minimum daily output from wind and solar generators combined is higher than if the system relied on either wind or solar alone.

Figure 24 Forecast distribution of VRE, solar and wind daily available capacity factors across the NEM with minimum, fifth percentile and median capacity factor, across all reference years, 2039-40

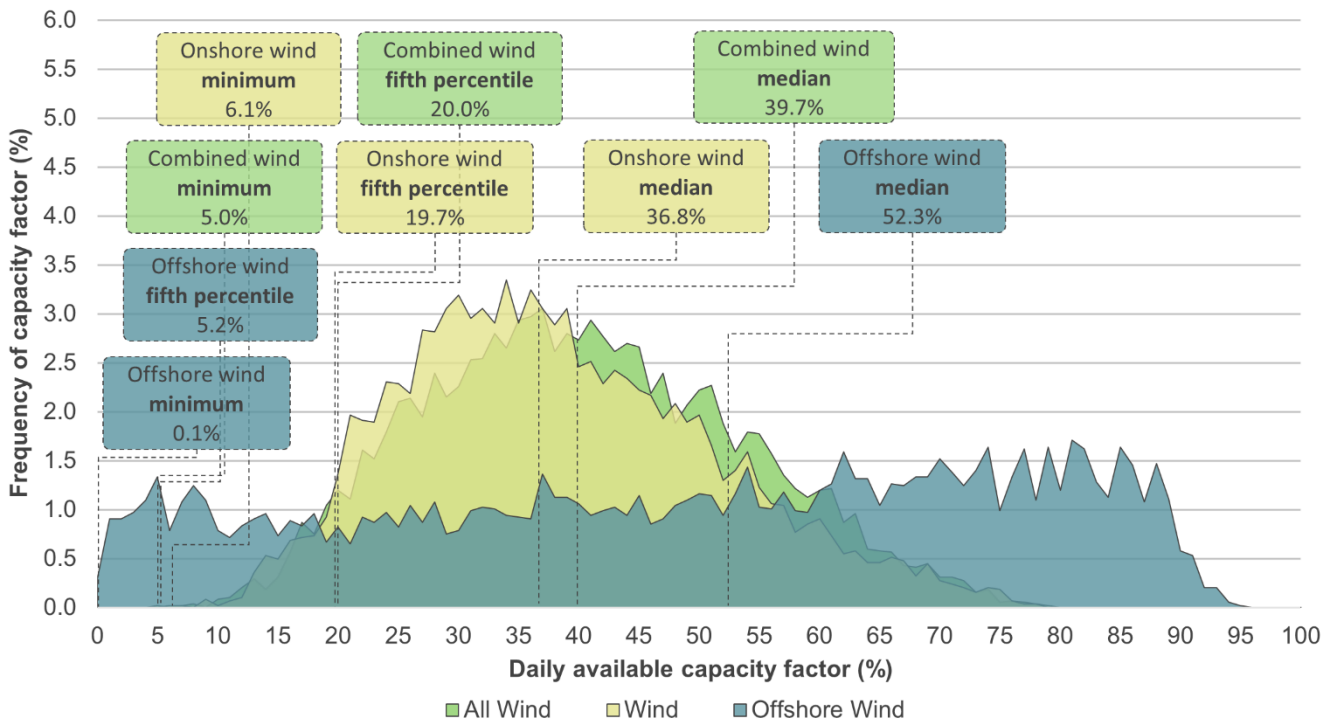


Note: Available capacity factor measures availability only without considering economic offloading or network curtailment. Total VRE in this figure is reported as the total availability of both wind and solar technologies relative to installed capacity, it is not the simple addition of the individual minimum capacity factors for solar and wind. The analysis applies the projected geographical distribution of these technologies, across regions and REZs in the ODP, and therefore is not a generic estimate of any wind farm or solar farm at any location.



Similar to a mix of wind and solar, a mix of onshore and offshore wind provides additional resilience by taking advantage of diverse wind resources. **Figure 25** shows how forecast daily capacity factors for offshore wind are relatively evenly distributed, while daily available capacity factors for onshore wind are more normally distributed around its median annual capacity factor. This technological diversity improves overall wind availability during periods of low onshore wind resource availability.

Figure 25 Forecast distribution of total wind, onshore wind and offshore wind daily available capacity factors across the NEM with minimum, fifth percentile and median capacity factor, across all reference years, 2039-40



Note: Available capacity factor measures availability only without considering economic offloading or network curtailment. The analysis applies the projected geographical distribution of these technologies across regions and REZs in the ODP, and therefore is not a generic estimate of any wind farm at any location. Offshore wind speeds follow a Weibull distribution and exhibit a broader range than onshore conditions, with more frequent very low and very high wind speeds. As a result, normalised offshore wind capacity factors are only slightly skewed toward peak output, with a relatively broad daily distribution due to suboptimal wind conditions at both extremes. These results are based on averaged daily capacity factors across 2011–2025 and from only two sites, which further flattens the distribution.

The ODP is capable of meeting demand during periods of very low VRE

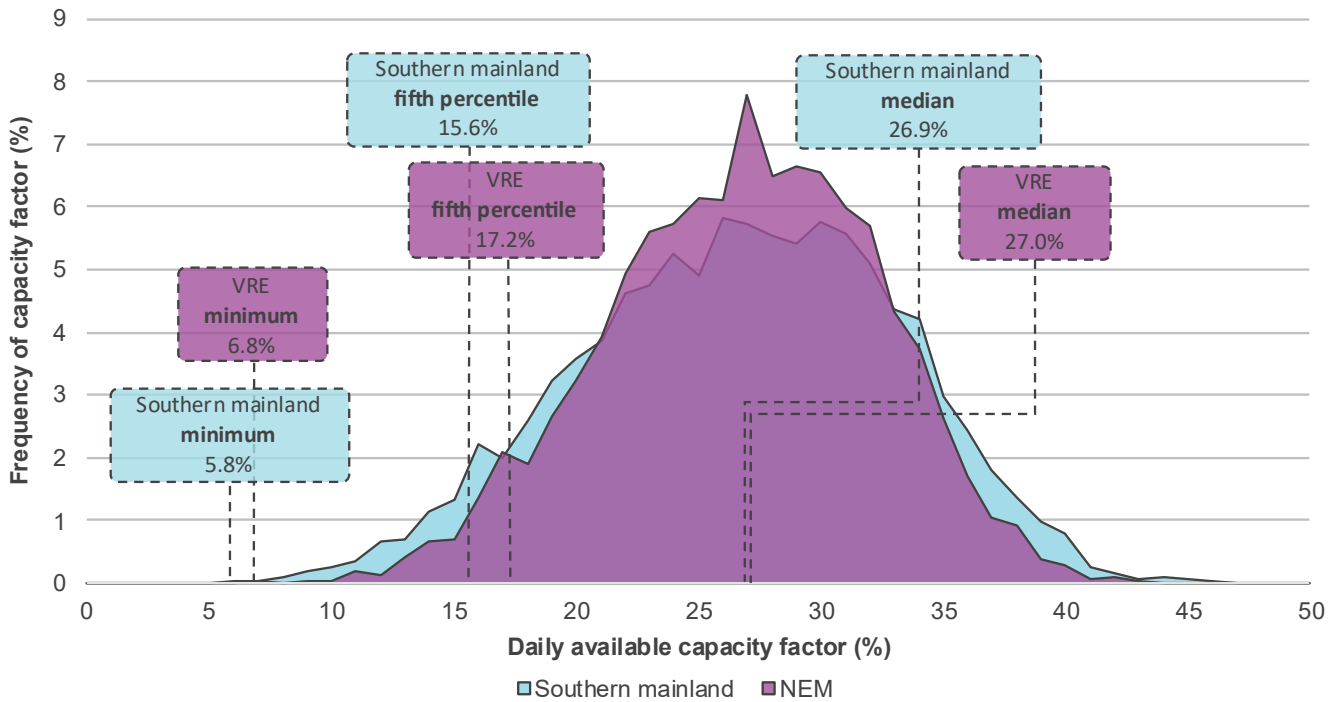
The geographic diversity of VRE generation and investment in network developments will help reduce reliability risks in periods of low renewable resources in any single NEM region by enabling the sharing of excess generation from one region to another experiencing lower renewable resource availability. This will also reduce the reliance on storage and flexible gas generation.

Winter months have lower solar availability with shorter days, which is more pronounced at higher latitudes in southern Australia, coinciding with colder conditions that increase heating loads (particularly as consumers electrify their traditional gas heating appliances). Victoria, South Australia and New South Wales are most exposed to these conditions while also providing limited geographical diversity, as weather conditions affecting one region tend to influence the weather of neighbouring regions.



As shown in **Figure 26**, the minimum, fifth percentile and median capacity factor of the southern mainland NEM is lower than that of the NEM as a whole.

Figure 26 Forecast distribution of VRE daily available capacity factors for the NEM and southern mainland regions with minimum, fifth percentile and median capacity factor, across all reference years, 2039-40



Note: Available capacity factor measures availability only without considering economic offloading or network curtailment.

While Tasmania also experiences fewer hours of daylight in winter, it also has significant amounts of hydro capacity that provide resilience to low VRE days. When the southern mainland is experiencing periods of low coincident VRE generation, Queensland and Tasmania can share excess generation through the transmission system.

Figure 27 shows the estimated dispatch mix in June 2040 in the lead up to and during the most severe VRE lull event assumed for the southern mainland regions in the 2026 ISP datasets. The ability for Queensland and Tasmania to export surplus generation during this period is limited by the capacity of the transmission system.

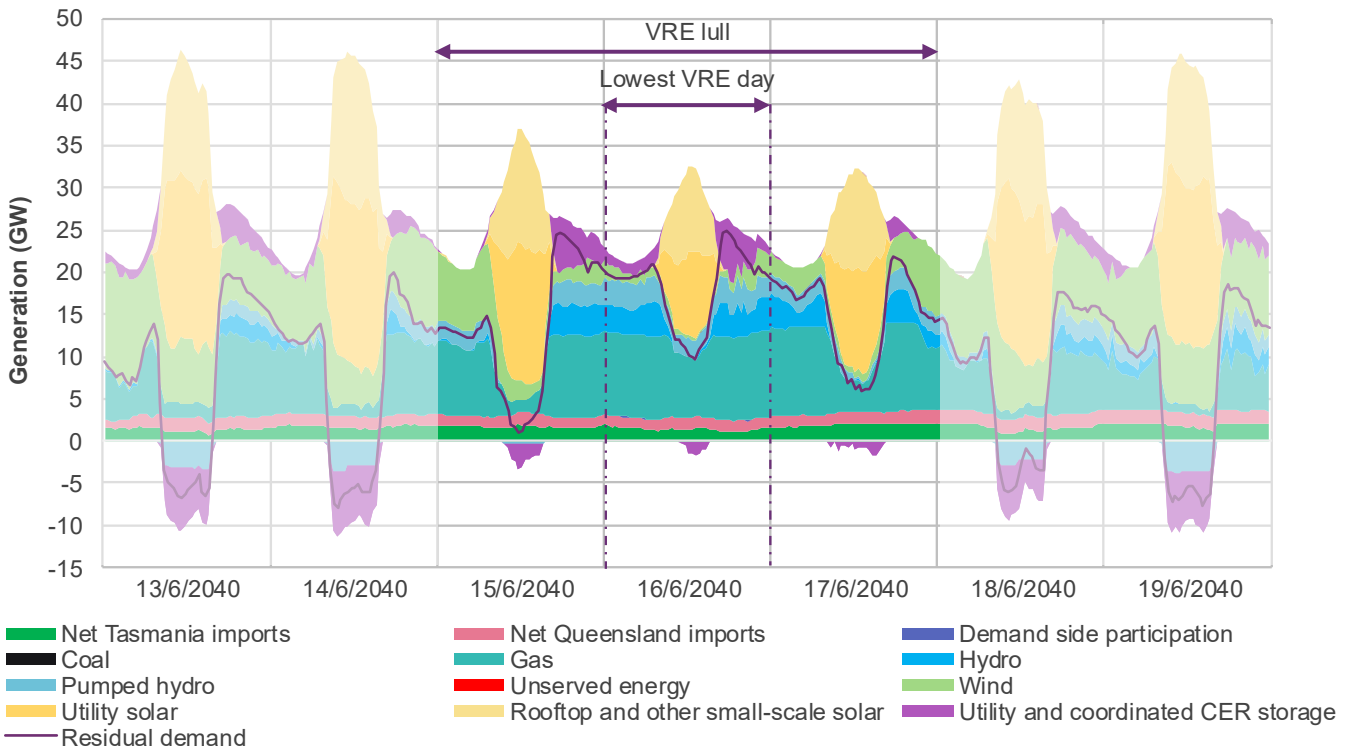
During this day of minimum VRE availability in the southern mainland:

- Southern mainland regions experience high heating loads and relatively low VRE availability due to still, cloudy, and cool weather conditions.
- The low VRE conditions are the most extreme on 16 June, which is the day of the southern mainland’s minimum available capacity factor for all VRE, but start from the afternoon of 15 June, with low solar production and relatively low wind output and continue into 17 June.
- On these days, sustained support is provided from hydro resources in New South Wales and Victoria (and through imports from Tasmania) made more accessible throughout the southern mainland by transmission augmentations in the ODP.



- Storages play a critical firming role by charging for short periods during the middle of the day when solar is more abundant and shifting that energy to support the evening peaks²⁰.
- Imports from Tasmania and Queensland are heavily relied on.
- Despite using all available hydro generation and storage capacity, gas generation is required to run continuously at maximum output to cover the VRE shortfalls, demonstrating its important back up role during VRE lulls.

Figure 27 Indicative operability across the southern mainland NEM regions (excluding Queensland and Tasmania) for the VRE lull with the lowest single day VRE period in 2039-40, Step Change (GW)



Note: gas includes flexible gas, mid-merit gas, biomass and diesel generators.

Prolonged low renewable output may also occur over longer periods. While **Figure 27** shows the single lowest VRE lull day, extended VRE lull conditions cause more significant energy deficits and increase the risk of reliability issues, particularly if the VRE lull events coincide with high volumes of electricity demand.

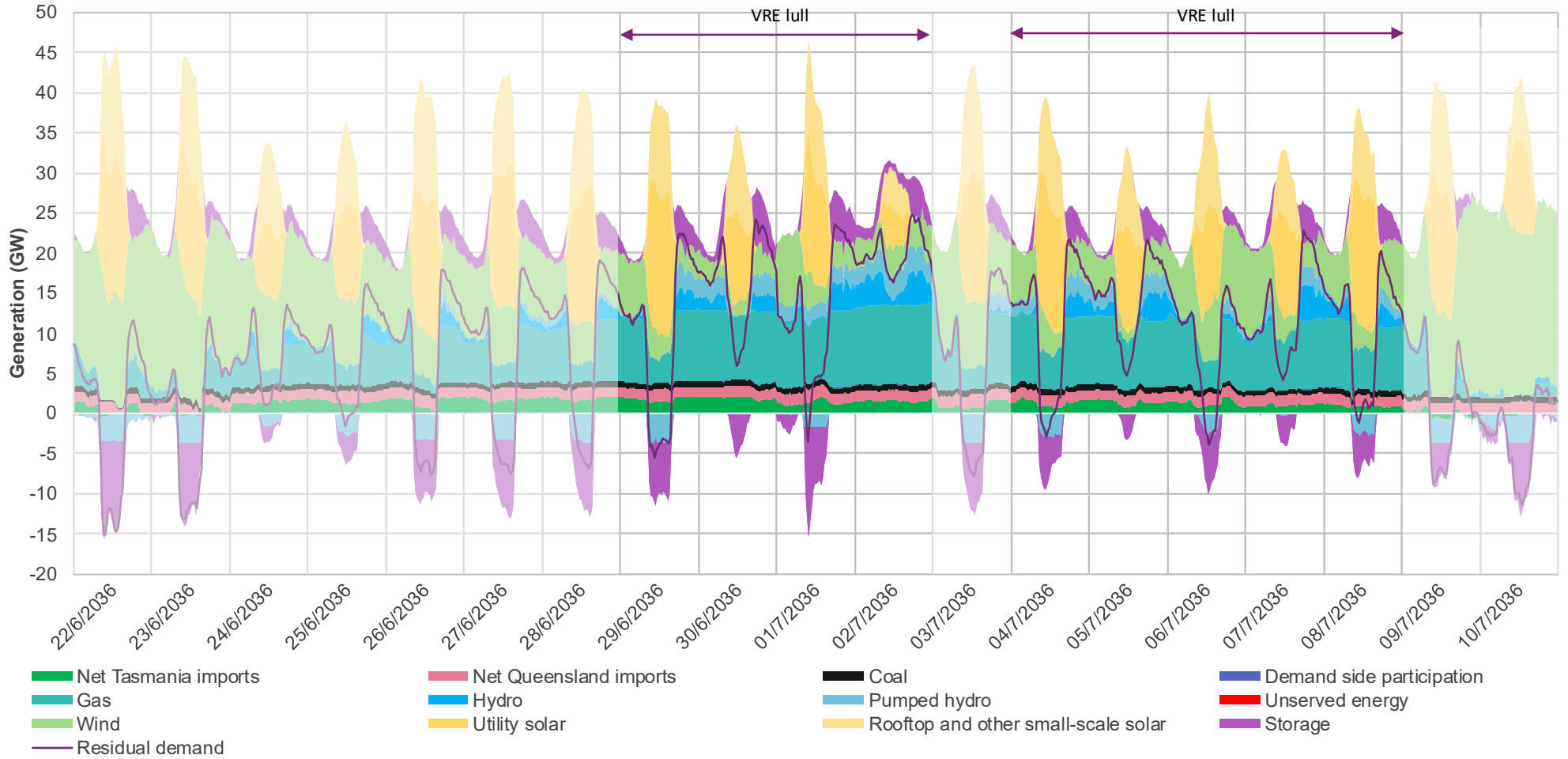
Figure 28 shows the indicative generation mix in the lead up to, and during, the tightest supply-demand conditions for the southern mainland NEM in the 2026 ISP dataset. While the days across the 15-day period are not all days of VRE lull, the elevated demand results in an extended duration of consistently high residual demand. The low VRE conditions are the worst during this period on 2 July in this dataset, when the VRE daily available capacity factor is the second-lowest of the year across the southern mainland, averaging just 6.5%.

This sustained period of high demand compared to relatively low VRE availability requires sustained gas generation and imports from other regions to maintain reliability of supply.

²⁰ As discussed in Section A4.6, storage operators are modelled to prepare for the upcoming low VRE periods by charging during daytime periods and preserving some of their stored energy for periods of VRE scarcity, assuming these conditions are forecast ahead of time.



Figure 28 Indicative operability across the southern mainland NEM regions (excluding Queensland and Tasmania) for the tightest supply-demand conditions in June and July 2036, Step Change (GW)



Note: this chart uses the strategic approach to storage management described below.



This 15-day period, from 24 June to 8 July in this dataset, shows periods of low VRE availability, and two VRE lulls, with a short period between each challenging weather condition. Managing storages during this period is expected to be most challenging, as there is limited ability to charge and fill shallow and medium storages on a daily basis. In milder conditions, storage management would be less critical, as storage operators would likely have capacity to re-charge storages between VRE lulls, and with sufficient foresight of these conditions could “pre-charge” using gas generation if necessary (and assuming batteries will be able to create energy arbitrage opportunities by later discharging at a compensatory higher price, despite charging on higher-cost generation). During extended low VRE conditions, or if the time between lull events was short, this would be more challenging, leading to an increased risk of energy deficit accumulation across the storage fleet.

Figure 29 shows the forecast energy availability and state of charge for storages of different depths during this period, demonstrating the critical role that storages are forecast to play in firming energy and meeting demand when VRE generation is less available.

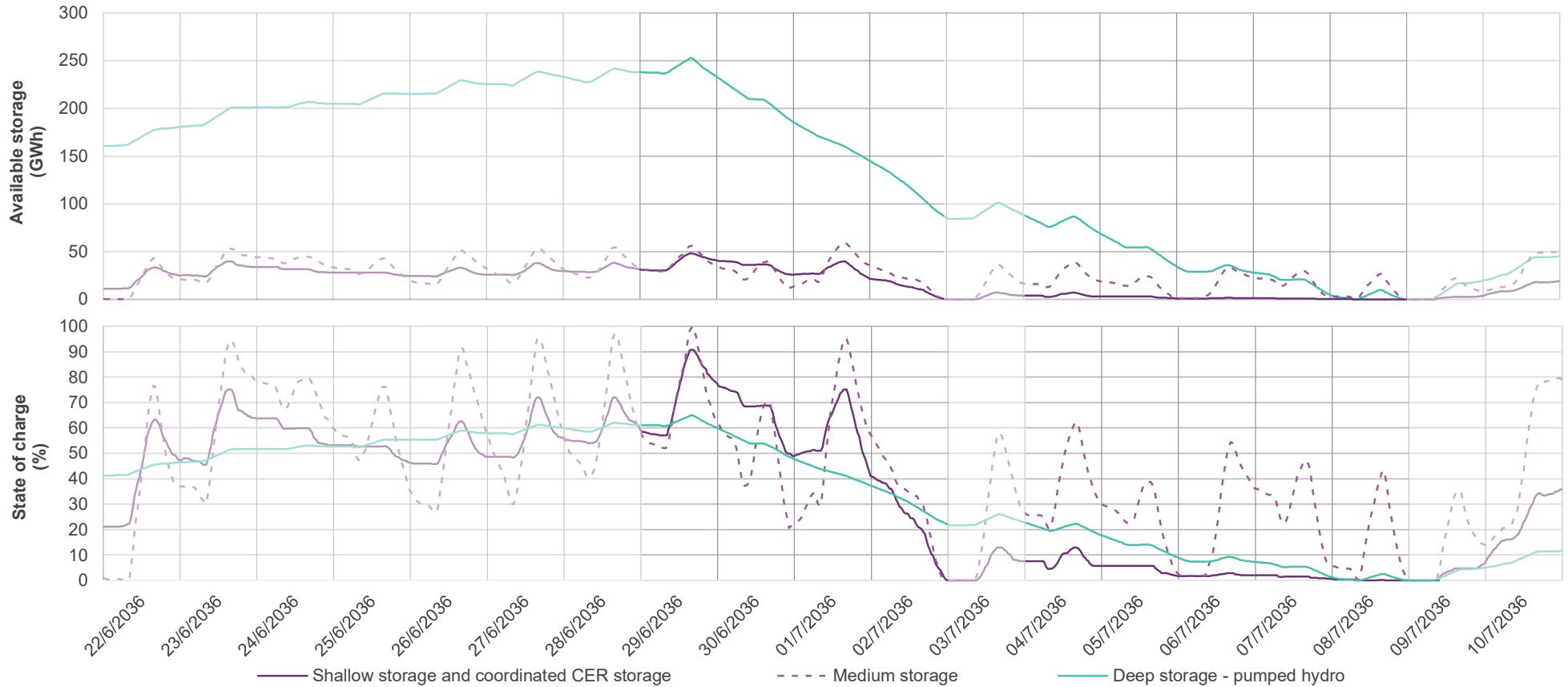
All depths of storage are heavily relied on during this period of high residual demand:

- At the beginning of this chart, deep storages²¹ which are made up of pumped hydro assets in the ODP, have close to 40% of the maximum potential stored water remaining, while all other storage assets are either depleted or significantly depleted. This reflects how there was already a prolonged series of high residual demand days leading up to the event that relied on the use of stored energy.
- On 22 June and 23 June, VRE availability is higher and storage levels are able to restore some of their discharged volumes, but remain below full capacity. On subsequent days, residual demand is higher and storages do not get an opportunity to fully recover the discharged volumes in the lead up to this period, especially deep storages.
- During the first VRE lull from 29 June to 2 July, storages are heavily utilised with deep storages discharging continuously. Storages are able to briefly recover on 3 July but then the low storage conditions persist during the second VRE lull that occurs from 4 July. Storage volumes are significantly lower at the beginning of the second VRE lull, demonstrating how an energy deficit is accumulated through a period of high residual demand.
- Storage assets continue to charge and discharge but are unable to materially recover state of charge until VRE availability improves from 9 July.

²¹ This analysis does not include hydro generators that operate their facility using deep water storage reservoirs.



Figure 29 Indicative behaviour of different storage depths in the southern mainland NEM for the tightest supply-demand conditions in June and July 2036, *Step Change*



Notes: All deep storages in the ODP are pumped hydros which are less efficient than batteries across a charge/discharge cycle. For this reason, it is assumed that during severe VRE lulls batteries will be used before deep storages to store energy. Pumped hydro reservoirs also have natural water inflows and are expected to charge at times during these events. This analysis does not include hydro generators that operate using deep water storage reservoirs.



Strategic operation of deep storages will be important to operate reliably and securely through prolonged periods of low VRE

Deep storages, like Snowy 2.0, Borumba and the NEM's existing deep reservoir hydro schemes, have an important role in ensuring reliability and providing resilience during periods of low VRE generation. Deep storages are capable of shifting energy between months and seasons, generally filling up in summer when VRE is more available and discharging during winter when residual demand is highest. However, as discussed in Section A4.6, deep storage operators must conduct charging and discharging activities with imperfect foresight. While short-term weather forecasts and generation and network outage transparency provide all operators with some level of foresight²², this will have limitations, and deep storages are not expected to have a reliable way to predict market conditions months in advance. As such, deep storage operators need to balance near-term opportunities to respond to immediate market conditions versus reserving stored energy for worse-case conditions that may (or may not) eventuate much later²³.

As an example, **Figure 30** shows the same 15-day forecast period in June and July 2036:

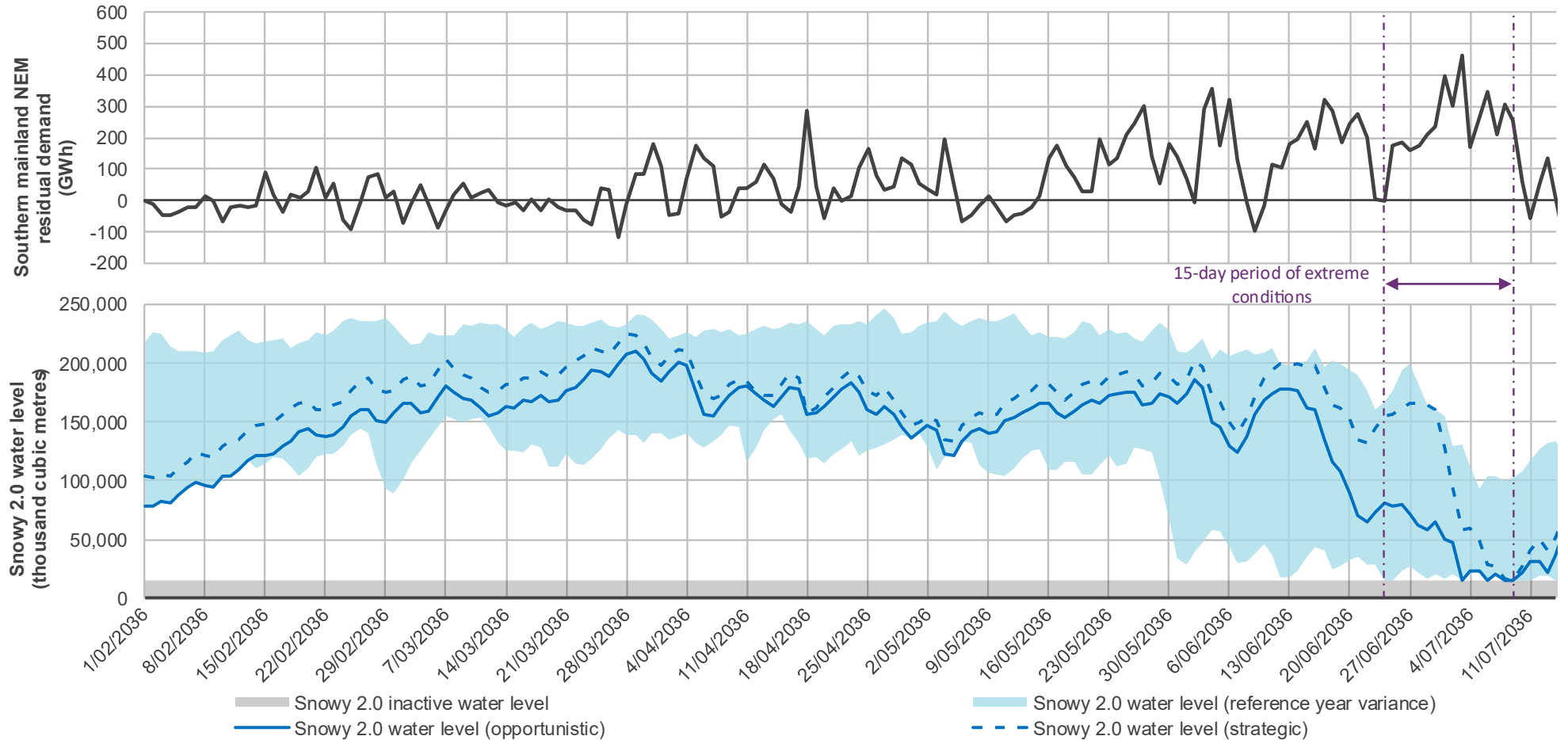
- The top chart shows the residual demand in the southern NEM for the period leading up to and during a 15-day period that represents the tightest supply-demand conditions in the southern mainland NEM of all weather conditions modelled (the 2011 weather reference year). This period exhibits very mild wind and low solar availability during winter. The water availability in Snowy 2.0 is shown in the bottom chart, with the shaded blue area demonstrating how other modelled weather conditions for the same period feature more, or less, severe outcomes for the winter.
- The solid blue line shows the water level for the 2011 weather reference year if Snowy 2.0 is operated to capture opportunities with little foresight, resulting in less conservative water management. If instead the facility attempted to maximise the value of its water, by reserving some for times when supply could be even more scarce, more water is held for potential later use, as shown by the dashed blue line. When this deep storage employs a more strategic water management approach that better accounts for future uncertainty, the stored water level is at a higher level leading into winter and is more available if VRE lulls occur (which occur in this weather sequence), reducing reliability risks.
- During mid to late June, stored water levels reduce as sustained high levels of residual demand occur when VRE availability is low, with greater need to use other generation sources. During these periods, gas generation would need to be deployed if storage operators retained their water reserves for periods of greater resource scarcity, as occurs in this example weather sequence in subsequent VRE lull periods.
- With an operating approach that puts higher value on stored water, illustrated by the dashed blue line, 169 gigawatt hours (GWh) of additional gas generation is needed between June 22 and July 10, including up to 40 GWh of additional gas generation in a single day. This additional gas generation preserves water storages, however would result in the faster drawdown of gas storages and would depend on gas infrastructure investments and gas storage management to ensure sufficient fuel was available. This interplay between gas and deep storages will most likely be a key consideration for long duration storage operators as they refine strategies to determine when to store energy and when best to release it for generation through the energy transition. See Appendix A10 Gas Development Projections for more information on the gas supply, infrastructure and storage required to meet NEM needs.

²² Analysis in this appendix assumes that a good forecast of weather and market conditions is available three days ahead.

²³ For the assessment of reliability in the 2026 ISP, deep storages were assumed to prioritise responding to immediate conditions, with less consideration given to future months. This assumption increases the likelihood of reliability issues and was adopted to help ensure the system is robust regardless of the approach taken by operators of deep storage assets.



Figure 30 Indicative southern mainland NEM daily residual demand (top) and Snowy 2.0 water levels (bottom) in challenging conditions, Step Change, February to July 2036



Notes: the water level of Snowy 2.0 is also affected by water inflows meaning it will not always be correlated to demand. The strategic storage management approach is also affected by different modelled forced outage patterns for thermal units like coal, impacting how much water Snowy 2.0 uses and therefore how much stored water is shown to be available on this chart.



Figure 31 shows the full projected generation mix during and in the lead up to the aforementioned conditions for the southern mainland NEM. In this example, deep storage operators do not hold sufficient stored water to operate through this period effectively, leading to a period of USE on 2 July. With maximum operation of other resources during this period, the lower availability of deep storage energy reserves means a greater reliability risk – if storages operated more conservatively prior to this period, with more gas generation ahead of these conditions to conserve stored water, this USE may be avoided.

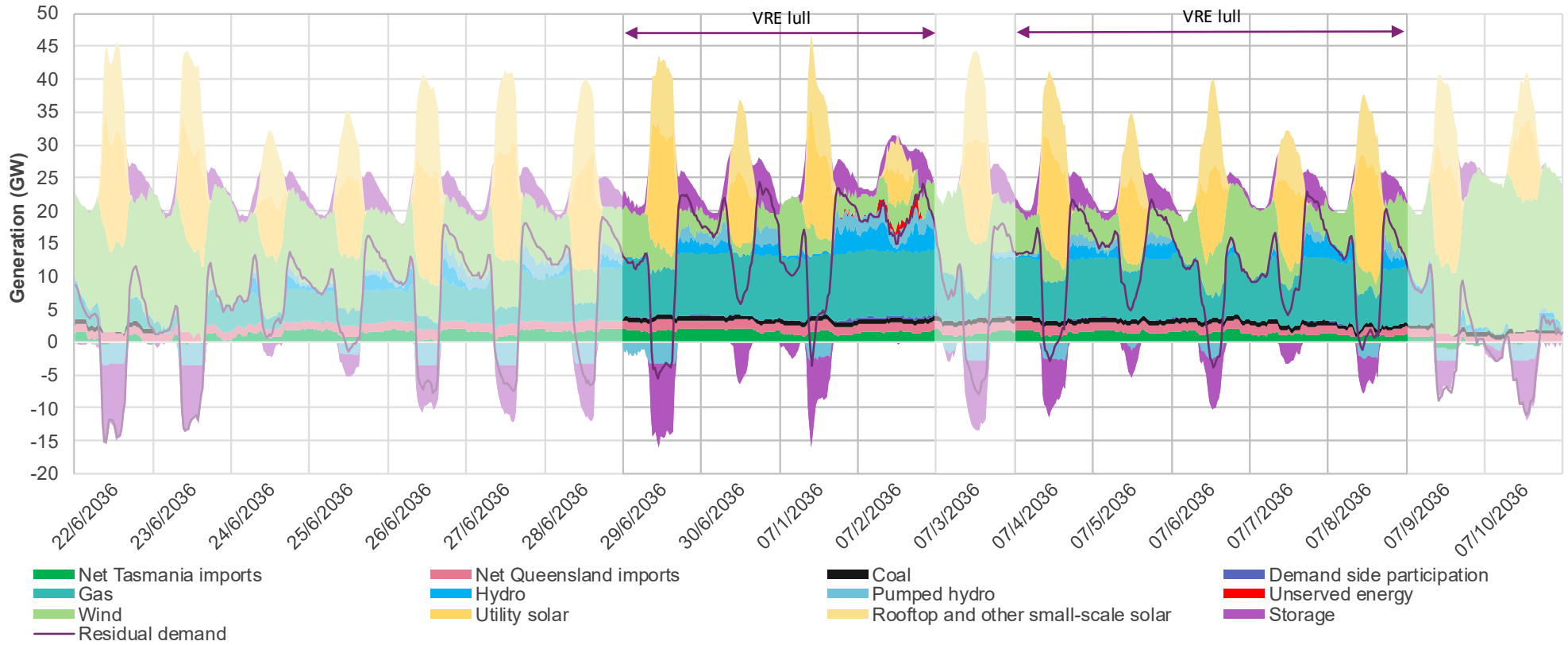
While USE is shown in this chart to demonstrate the importance of deep storage operations, the ODP remains under the reliability threshold for all regions across all reference years (see Section A4.8).

While such extreme weather conditions are expected to be rare, this analysis demonstrates the critical role of deep storages during extended periods of low renewable availability and high demand, as well as the important role of other complementary dispatchable resources such as gas generation. The analysis also shows how stored water, like other forms of stored energy, has intrinsic value that varies with market conditions. Storage operators will need to consider how to value this asset to take advantage of later, uncertain opportunities that may be of very high value.

While every power system has its own unique challenges, other systems internationally have high exposure to weather-dependent generation, including New Zealand with its high penetration of hydro assets – and Tasmania is also dominated by hydro generation. In future ISPs, AEMO will seek to leverage this national and international experience to test likely storage management strategies that adapt to the future NEM's unique generation mix in a way that reduces reliability and security risks while appropriately valuing stored water.



Figure 31 Indicative operability across the southern mainland NEM during extreme supply-demand conditions in June and July 2036, Step Change (GW)



Notes:

- While USE is shown to occur in these specific conditions, the ODP is under the reliability standard.
- Gas includes flexible gas, mid-merit gas, biomass and diesel generators.
- An unplanned outage of 730 MW of coal from 23 June to 29 June exacerbated the low renewable energy conditions, requiring greater use of alternative energy sources (increasing the potential to draw on deep storage resources during this period).



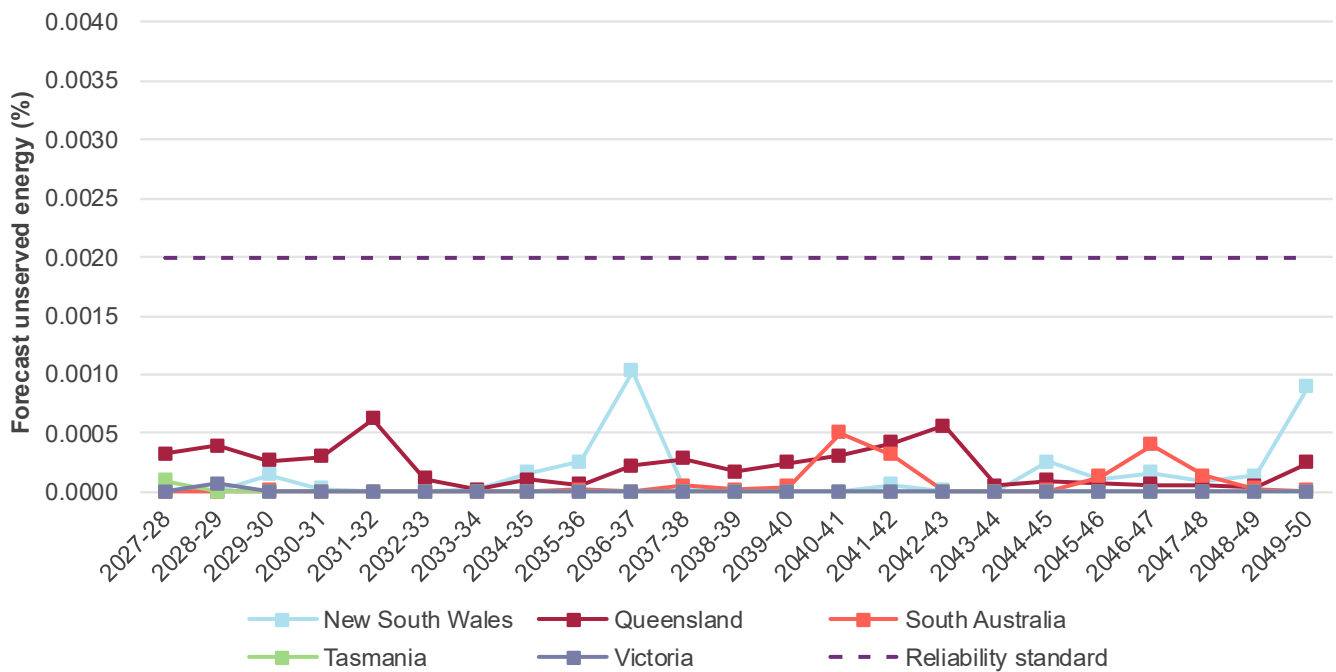
A4.8 The ODP maintains reliability during the transition

The reliability standard is a measure of the maximum expected USE in each region that is acceptable over the long term, requiring that it does not exceed 0.002% of energy demand in any financial year. This reflects a trade-off between reliability and cost, as determined by the Australian Energy Market Commission’s (AEMC’s) regular assessments of the reliability standard and its accompanying reliability settings²⁴, recognising that eliminating all USE would require inefficient over-investment in generation and network capacity.

AEMO has forecast reliability outcomes for the 2026 ISP’s ODP using an approach consistent with the reliability assessments conducted for the NEM 2025 *Electricity Statement of Opportunities* (ESOO), although with some simplifications²⁵. The reliability approach in this ISP provides a higher-level representation of weather variability, generator outages and the NEM transmission system than the ES00²⁶.

With the 2026 ISP’s generation, storage and transmission developments in the ODP, forecast USE is within the reliability standard in all regions over the medium and longer term, as shown in **Figure 32**.

Figure 32 Forecast reliability outcomes by region for the ODP, Step Change, 2027-28 to 2049-50



This assessment has identified summary insights consistent with previous ES00 and ISP reliability analyses, primarily that:

²⁴ On 23 April 2026, the Reliability Panel recommended that the NEM reliability standard is increased to 0.003% as part of the 2026 Reliability Standard and Settings Review. This change is yet to be confirmed through a rule change. For more information, see <https://www.aemc.gov.au/market-reviews-advice/2026-reliability-standard-and-settings-review>.

²⁵ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

²⁶ To manage simulation complexity, this reliability analysis has simulated fewer random generator outage patterns and reference years than is applied to do a formal reliability assessment in the ES00. Also applied is a simpler representation of the transmission system than the ES00 reliability modelling, with sub-regional transfer constraints rather than the detailed transmission representation used in the ES00.



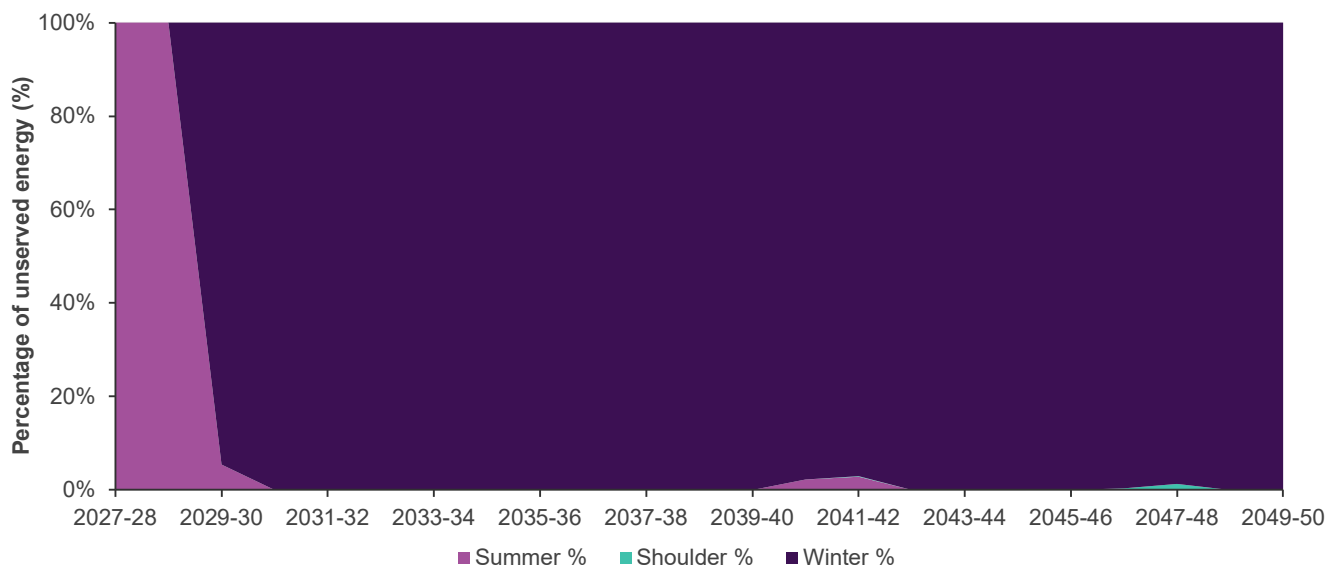
- Reliability risks shift from summer to winter in the southern mainland NEM, as the grid evolves from a capacity-constrained power system to one with greater energy adequacy challenges (particularly during VRE lulls as discussed in Section A4.7).
- Reliability risks vary with different weather conditions and over time, as coal capacity retires from the power system and there is a transition to a renewables-based system that is more influenced by weather conditions.

Changing nature of reliability risks

As discussed in Section A4.7, VRE lulls create circumstances which can cause shortfalls in total energy production over hours, days or even weeks, driving a shift in the nature of reliability risks which have historically been caused by shortfalls in instantaneous generation when electricity demand peaks, during summer for most regions. In southern regions, VRE lulls are more likely in winter with increased winter demand due to electrification of heating loads and reduced solar output in winter when days are shorter.

Figure 33 shows how in the longer term, as the NEM moves towards an increasingly VRE-based system with a large amount of storage capacity, reliability risks are forecast to shift seasons from summer to winter in the southern mainland NEM. Risks are forecast to become primarily driven by VRE lulls, when reduced winter solar output coincides with extended periods of low wind, creating a challenging supply-demand balance. In these circumstances, the availability of sustained firming generation such long duration storage and flexible gas will be essential to mitigate the risk of USE.

Figure 33 Seasonal share of forecast USE in southern mainland NEM, Step Change, 2027-28 to 2049-50



Note: while this chart shows the seasonal share of forecast USE outcomes, the total magnitude of USE remains low and within the reliability standard for all years.

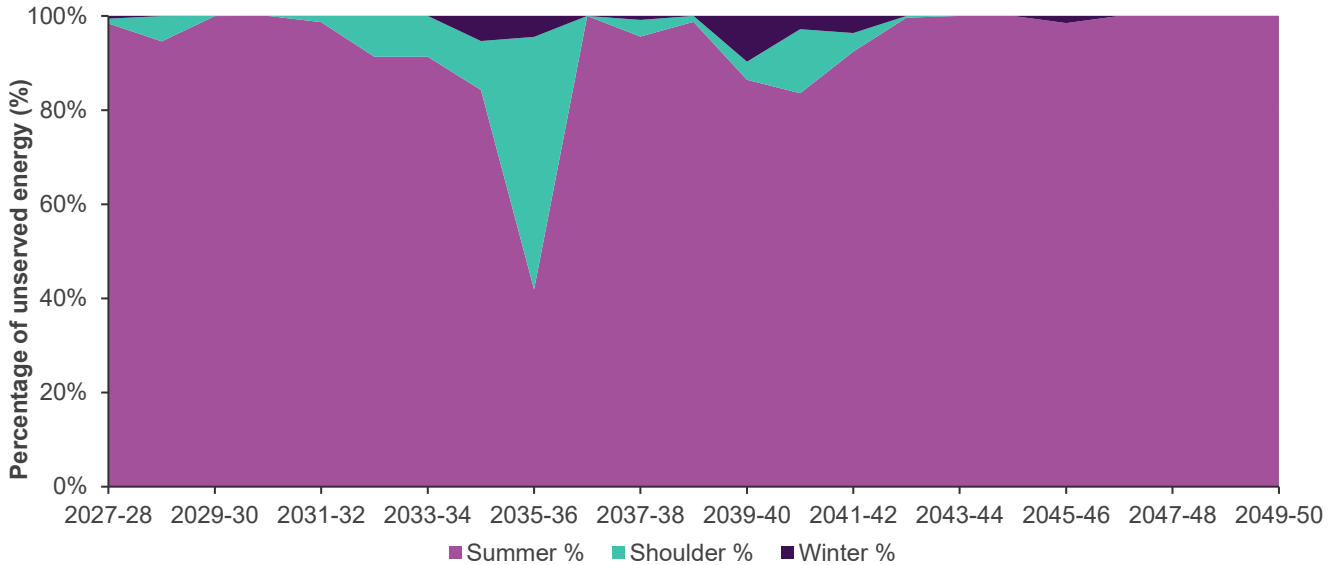
Unlike the southern mainland NEM, **Figure 34** shows how reliability risks in Queensland are forecast to continue to be driven by instantaneous peak demands in summer months due to the significant demand for cooling and more consistent seasonal solar output throughout the year. Risks are most likely to arise when significant generation outages in Queensland coincide with VRE lull events.

Reliability risks in the NEM vary with differing weather conditions, and also over time as existing capacity retires and the system becomes more reliant on firmed renewable energy. **Figure 35** shows the forecast USE for different weather reference years across the whole NEM from 2029-30 to 2044-45. The dotted line shows the average forecast USE across all



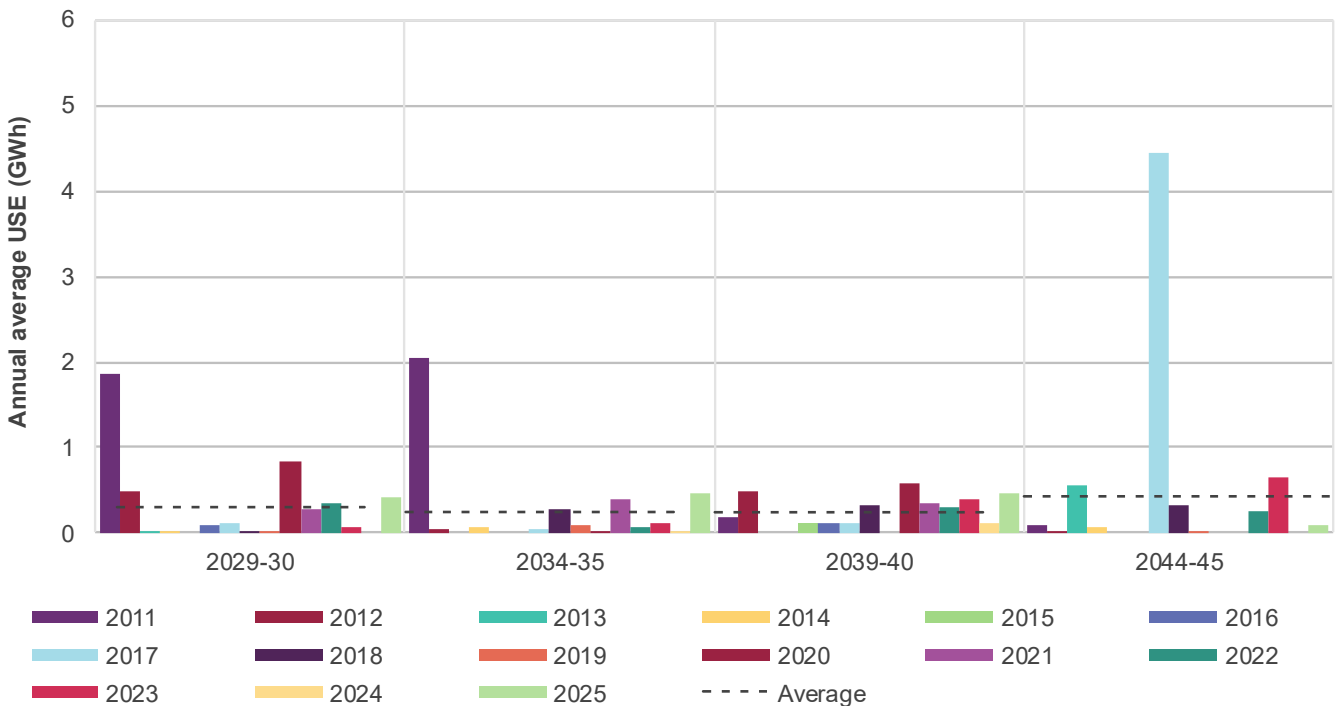
simulated weather reference years. This figure highlights the impact of variable weather conditions, with some reference years having significantly larger reliability risks, while most have much lower risk. This indicates that the ODP is resilient to a broad range of weather conditions, but may be severely impacted during low probability events. While the reliability standard is still being met in every year, tail risks exist that could create significant supply scarcity risks, depending on the availability of firming and back up resources in the NEM.

Figure 34 Seasonal share of forecast USE in Queensland, Step Change, 2027-28 to 2049-50



Note: while this chart shows the seasonal share of forecast USE outcomes, the total magnitude of USE remains low and within the reliability standard for all years.

Figure 35 Average NEM-wide unserved energy by reference year, Step Change, 2029-30 to 2044-45



Note: While the reliability standard is defined on a regional level, for perspective, 0.002% of USE in the NEM for 2044-45 is equivalent to 7.32 GWh.



Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the Australian Energy Regulator's (AER's) Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	<p>Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window.</p> <p>For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable.</p> <p>Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.</p>
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Actionable New South Wales project and actionable Queensland project	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	<p>A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths.</p> <p>Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.</p>
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand apply, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.



Term	Acronym	Explanation
Demand-side participation	-	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity, and is a form of 'demand flexibility'.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Economic offloading	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. This may also be referred to as economic 'spill' or 'spilled energy'.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Mid-scale	-	<p>Generation and storage typically connected to the distribution network rather than to either the transmission network or behind the meter at a business or residence. For the 2026 ISP, these resources are assumed to have a generation or charge/discharge capacity of between 5 MW and 30 MW. For ease of reporting in this document, mid-scale generation and storage are sometimes included within the totals for utility-scale generation and storage.</p> <p>In other AEMO documents, such as the <i>Demand Side Factors Information Guidelines</i> and the <i>ISP Methodology</i>, these resources are sometimes referred to as 'other distributed resources'.</p>
National Electricity Rules	NER	The Rules are legally binding rules made under the National Electricity Law, which govern the operation of the National Electricity Market and the ways in which AEMO manages power system security. The Rules also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The Rules are mainly made by the AEMC having regard to the National Electricity Objective.
Net market benefits	-	<p>The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.</p> <p>The net market benefits of the ODP through to 2050 is the difference between the cost of the ODP and the cost of a 'counterfactual' development path which has no new transmission build.</p>
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development

Term	Acronym	Explanation
		opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate energy to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: “solar, wind, biomass, hydro, and hydrogen turbines”. Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as a high-quality resource area where a cluster of large-scale renewable energy projects can be developed using economies of scale.
Renewable lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Rooftop and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial “non-scheduled” PV systems.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For this ISP, AEMO has considered three scenarios: <i>Slower Growth</i> , <i>Step Change</i> and <i>Accelerated Transition</i> .
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how sensitive modelling outcomes are to a change in input or assumption (or a collection of related inputs and assumptions).
Spill	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. Also referred to as ‘economic offloading’ or ‘spilled energy’.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Utility-scale or utility		For the purposes of the ISP, ‘utility-scale’ and ‘utility’ refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia’s Energy Ministers in February 2024.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.