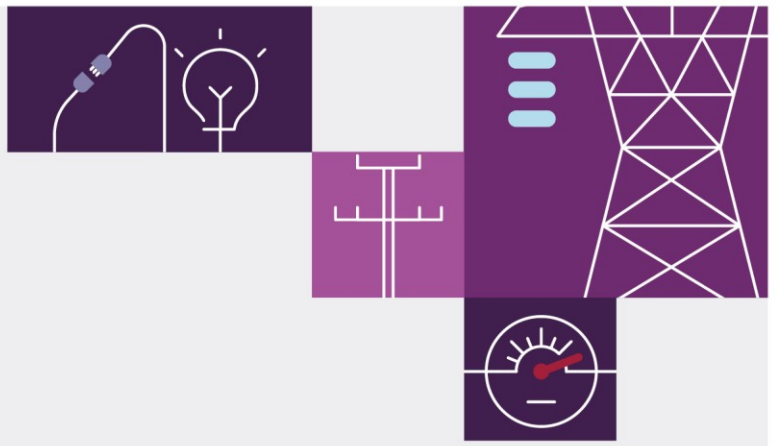


Appendix 4. System Operability

June 2024

Appendix to the 2024
Integrated System Plan for the
National Electricity Market





Important notice

Purpose

This is Appendix 4 to the 2024 Integrated System Plan (ISP) which is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>. AEMO publishes the 2024 *Integrated System Plan* (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 1 May 2024 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	26/6/2024	First release

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.



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Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path (ODP) sets out the needed generation, storage and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

This appendix details the modelling AEMO has undertaken to assess the operability and reliability of the ODP identified in the ISP. This relies on a short-term time sequential model, which forecasts dispatch of the electricity market on a 30-minute basis. The analysis of modelling results shows the system can operate reliably across all timeframes under more variable and sometimes extreme conditions.

The National Electricity Market (NEM) is forecast to be reliable out to 2050

The ODP set out in the 2024 ISP is forecast to maintain NEM reliability in all regions for all years. The *reliability standard* requires that expected annual unserved energy (USE) does not exceed 0.002% of the total annual energy needs in each region. The *interim reliability measure* (IRM) is also in place until 2028 and requires expected USE to not exceed 0.0006% of total annual energy needs in each region.

The way consumers use electricity will continue to evolve

The way that consumers use electricity supplied through the electricity transmission and distribution networks is set to continue to change, and potentially evolve significantly with the continued uptake of consumer energy resources (CER), the electrification of industry, businesses, homes, and transportation, and the development of hydrogen-related loads.

Daily load patterns will become more variable, with distributed photovoltaic (PV) systems embedded within the distribution system supplying an increasing proportion of customer loads, and operational demand (delivered from the transmission system) will therefore become even more variable. Seasonal variations will become more pronounced during winter, with higher energy consumption as heating loads are electrified and reduced distributed PV output on the shorter days of the year. Resource flexibility, deep energy storages and backup fuel diversity will be required to manage increased variability in operational demand across varying weather conditions and increasingly seasonal energy production profiles.

Variable renewable energy (VRE) penetration increases operational complexity

Operating the power system reliably with more VRE and fewer synchronous generators will present daily, weekly and seasonal challenges. Investments in transmission, VRE and storage will enable surplus energy to be used to meet demand where and when resources are less available. Solar will become the main energy source during daylight hours, complemented by wind energy and storage in the evening and overnight, with gas backing up this diverse resource mix. Geographic and technological diversity of the supply mix will help reduce the risks of poor weather conditions.

During longer periods of low VRE generation, the system will rely on transmission to deliver resource diversity, as well as on deeper storage technologies, hydro and gas-powered generation (GPG). The highly variable residual demand (demand that is met by scheduled units, net of VRE and CER output) will require generators with



sufficient ramping capability and available energy across all operational timeframes to balance and firm renewable generation.

Longer, dark and still weather conditions will increase operability difficulties

From time to time, the power system will experience extended long, dark and still weather patterns over a wide geographical area, meaning VRE output is low for several consecutive days. These extended VRE ‘droughts’ are rare and, over the longer term, extremely difficult to predict in duration and intensity. Resource diversity – particularly geographical diversity – will help mitigate the effects of localised low renewable conditions associated with adverse weather in a single area, but occasionally weather systems across larger areas of the NEM can reduce overall availability. By applying some of the most severe weather conditions observed historically and extending their duration significantly, the ODP has demonstrated resilience to extreme weather conditions, through the effective operation of diverse VRE resources, storage, GPG and hydro generation.

GPG provides critical support but gas supply can be constrained

Gas generators are a critical part of the current and future supply mix, and the role GPG plays is changing. The flexibility gas provides to support peak demands and maintain energy adequacy is expected to be particularly important during periods of low VRE generation.

AEMO anticipates that GPG may become constrained during peak periods when demand for gas heating and industry is also high, which may lead to the need for secondary fuels and utilisation of other back-up forms of generation, and increased investment in gas production, pipeline and storage capacity. To effectively back up VRE and storage generators, future flexible GPGs will need access to firm uninterrupted fuel supply. GPG siting decisions will therefore need to consider the availability of gas infrastructure, and prudent investments in on-site storages for liquid fuels to enable continued operation if gas supply becomes constrained at locations across the NEM.

The 2024 ISP’s optimal generation development therefore assumes new GPG will be built with dual fuel capability and liquid fuel storage on-site for periods when gas supply through the east coast gas system is constrained. This local investment will ensure that the electricity system maximises its forecast reliability through the provision of adequate alternative fuel during extreme weather events, reducing the risk of electricity consumers experiencing constraints to supply related to the limitations of gas infrastructure. Ongoing investment in gas supply, transport and storage will also be necessary to ensure adequate fuel can be delivered to GPGs.



A4.1 Introduction

This appendix supplements the 2024 ISP with additional analysis on the operability and reliability aspects of the ODP. It presents a granular assessment of operational dynamics and reliability challenges as the power system transitions to much higher levels of VRE.

This appendix presents a NEM-wide view and provides regional breakdowns where appropriate for the analysis AEMO has used in this assessment. In this appendix:

- A4.2 examines how demand profiles will continue to evolve and the impacts on power system operations.
- A4.3 provides forecasts and analysis for VRE penetration and curtailment.
- A4.4 analyses the requirement for resource flexibility to manage increased variability in supply and demand.
- A4.5 tests the operational resilience of the ODP during extended long, dark, and still weather conditions.
- A4.6 investigates the role of storage technologies in firming VRE and examines alternative approaches to modelling for imperfect foresight of short-duration storage devices.
- A4.7 examines the operational challenges for coal-fired power stations during the transition and analyses approaches to maintaining profitability.
- A4.8 presents integrated modelling and analysis across the gas and electricity systems and examines the impacts of gas system adequacy on power system operability.
- A4.9 summarises the reliability outcomes for the 2024 ISP ODP and analyses the seasonal risks facing the power system.

The content in this appendix is complemented by Appendix 7: System Security, 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 2024 ISP

- Updated committed and anticipated projects as per the 2024 February Generation Information update.
- Changes to earliest in-service dates (EISD) and costs for several transmission projects.
- Inclusion of the expanded Capacity Investment Scheme (CIS) targets.
- Change in the sub-regional allocation of demand in New South Wales.
- Updated treatment of hydrogen demand to better represent demand location and to include committed projects.
- The VRE drought analysis has been extended to include an assessment of operational reliability during intermittent VRE droughts, and examines conditions of very low VRE output coinciding with high underlying demand.
- The integrated gas and electricity market analysis has been updated to explore dispatch outcomes for GPG and now includes the operation of on-site liquid fuel storages.
- The reliability outlook has been updated for the 2024 ISP ODP, which shows lower forecast risk of unserved energy (USE) across the horizon.



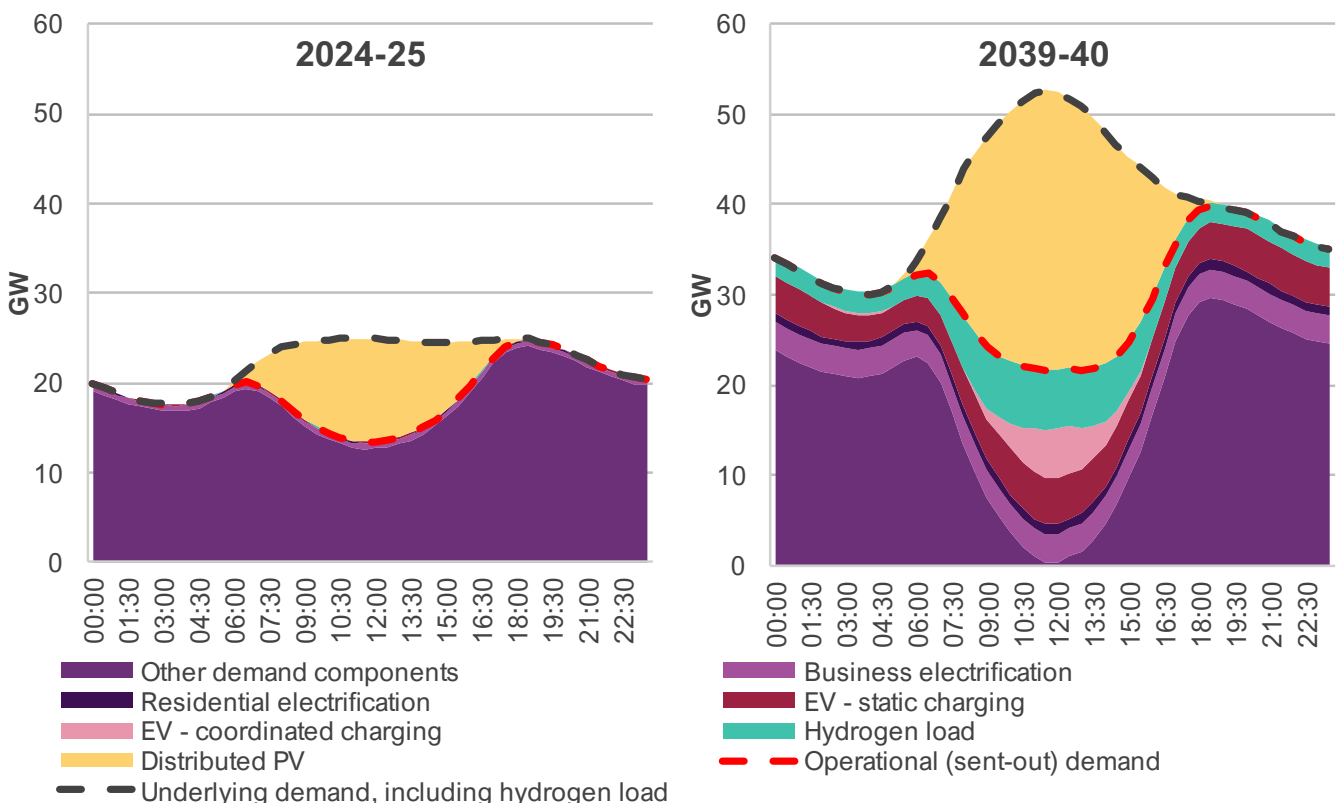
A4.2 The NEM's demand profiles will continue to evolve

Future electricity usage is forecast to continue to change, and the electricity system will need to adapt appropriately to meet the needs of consumers. Fuel-switching away from traditional fossil fuels is anticipated as households and businesses seek to reduce emissions, leading to a rise in electricity consumption and peak demand.

Economic drivers such as population growth and increased economic activity are projected to continue increasing the demands on the power system to supply energy, while improvements to building and appliance efficiency, and the uptake of distributed PV, are expected to moderate growth in household consumption. The emergence of new technologies such as hydrogen production and electrified transport charging are projected to increase operational demand. Daily usage patterns will be influenced by CER, including distributed PV, electric vehicles (EVs), and household or community batteries, which will provide new capability for consumers to use energy from the grid more flexibly.

Figure 1 illustrates the role of CER, electrification, and emerging technologies such as hydrogen production in the forecast evolution of demand in the NEM, by showing the average annual time-of-day demand profiles forecast for 2024-25 and 2039-40 in the *Step Change* scenario.

Figure 1 Forecast average annual demand profile for the NEM, 2024-25 and 2039-40, Step Change (GW)





Demand definitions

- **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 PV and battery storage.
- **Residual demand** refers to demand that cannot be met by VRE generation technologies and must be met by other generators or storage.

The daily demand profile is forecast to change significantly by 2039-40, as a result of growth in:

- **EV charging**, which is projected to increase underlying demand significantly over the forecast horizon. The impact on daily demand profiles will depend on consumer charging behaviours and be influenced by the availability of charging infrastructure and the capacity of vehicles to store charge. Some vehicle owners may prefer to 'top up' their batteries daily, enjoying the convenience of a full charge, while others may charge less frequently when the battery level falls below a certain threshold. Charging behaviour is not anticipated to be uniform, and patterns that focus on driver 'convenience' will contrast with behaviours that are incentivised to reduce electricity system impacts. Convenience charging may add to peak demand as drivers plug in their vehicles when they return home. In addition to convenience based charging behaviours:
 - Smarter charging patterns are expected to become more widespread over time as vehicle owners shift away from convenience charging towards middle-of-day charging. This could be encouraged by appropriate time-of-use (TOU) electricity tariffs and enabled by more widespread availability of charging infrastructure.
 - Coordinated charging and discharging, through vehicle-to-home (V2H) and vehicle-to-grid (V2G) services, are forecast to emerge, which may contribute to reducing operational demand. This form of CER orchestration provides automated smart charging of EVs, using predictive artificial intelligence (AI) to optimise vehicle charging to time periods when operational demand is low and PV generation is high. EVs also have potential to be dynamically controlled to provide V2H and V2G services by charging at home or work during the day and discharging during the evening to reduce peak demand from the grid.
- **Electrification** of household and business gas appliances and viable industrial processes, which is forecast to substantially increase underlying demand. While industrial electrification introduces little additional seasonality, residential electrification of heating will lead to higher demand in winter compared to summer¹.
- **Distributed PV system** uptake, which is forecast to continue and further reduce daytime operational demand. **Consumer-owned battery storage** uptake is projected to increase, further reducing households' reliance on electricity sourced from the grid and enabling surplus daytime energy to be stored and discharged later in the evening. Independently operated **passive CER storage** systems can also be **coordinated CER storage**, where, for example, these systems can be brought together through a virtual power plant (VPP) and can

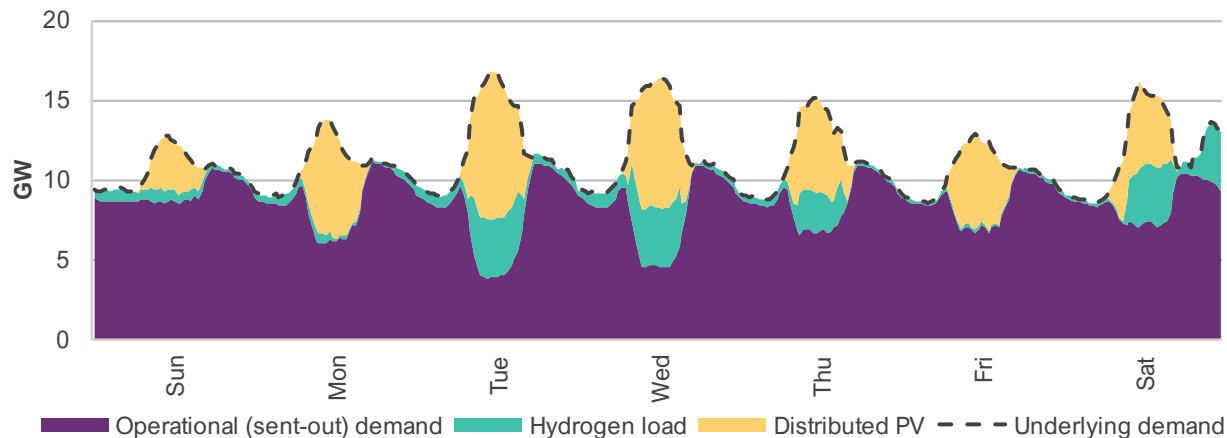
¹ Figure 1 depicts an average annual demand profile, therefore the impact of higher heating demand in winter is diluted by averaging across the other seasons where electrification of heating load is not as pronounced.



collectively charge and discharge at times compatible with power system requirements, which can enhance system reliability and security.

- **Hydrogen load** (electricity demand from hydrogen electrolysis or ammonia production), which could be substantial but depends on the development of domestic and global hydrogen industries.
 - Hydrogen electrolyzers were assumed to operate flexibly, potentially reducing electricity consumption when renewable energy resources are limited (during dark or still conditions, including overnight) and consuming more during daylight hours when excess solar energy is abundant.
 - Hydrogen load in this ISP modelling is therefore expected to lift minimum demand and have minimal impact at times of peak demand. It is also expected to be technically capable of providing flexibility by turning off for whole days when weather conditions are unfavourable, depending on the commercial implications of doing so. The appropriateness of these assumptions will become clearer as the hydrogen industry develops, and more information becomes available regarding electrolyser flexibility, hydrogen consumer flexibility, and the impact of hydrogen infrastructure (such as pipeline availability, and hydrogen storage solutions). Appendix 2 (Section A2.5.6) explores the impact of reduced hydrogen electrolyser flexibility on electricity generation and storage developments, and electrolyser demand.
 - Figure 2 illustrates the potential scale of hydrogen load flexibility in Queensland across a sample week in 2040, where hydrogen load follows high solar or wind generation and fills troughs in operational demand.

Figure 2 Projected week of hydrogen electrolyser load in Queensland in 2040, Step Change (GW)

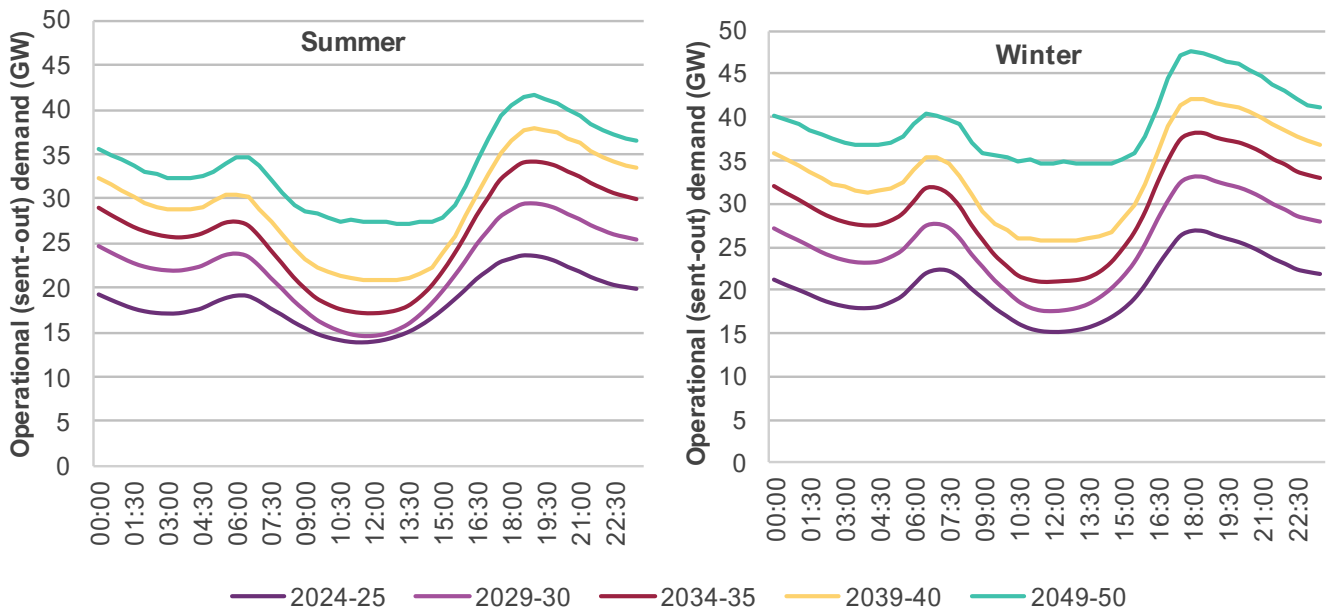


- **Other demand components** such as demand management programs and smart home management systems, which could shift appliance load to the middle of the day when distributed PV output is typically highest.

Figure 3 shows the forecast evolution of the average time-of-day demand profile for summer and winter seasons. During summer, demand profiles exhibit lower midday troughs due to higher distributed PV output, despite being offset by additional load from hydrogen production and EV charging. In the absence of hydrogen production, the average midday summer demand is projected to be only 15 gigawatts (GW) in 2049-50. During winter, demand is expected to increase as electrification of heating loads causes daytime operational demand to rise with lower distributed PV output.



Figure 3 Operational sent-out demand average time-of-day forecasts, summer and winter, *Step Change*, 2024-25 to 2049-50 (GW)



Note: Operational sent-out demand profiles include electricity consumed in the production of hydrogen or ammonia.

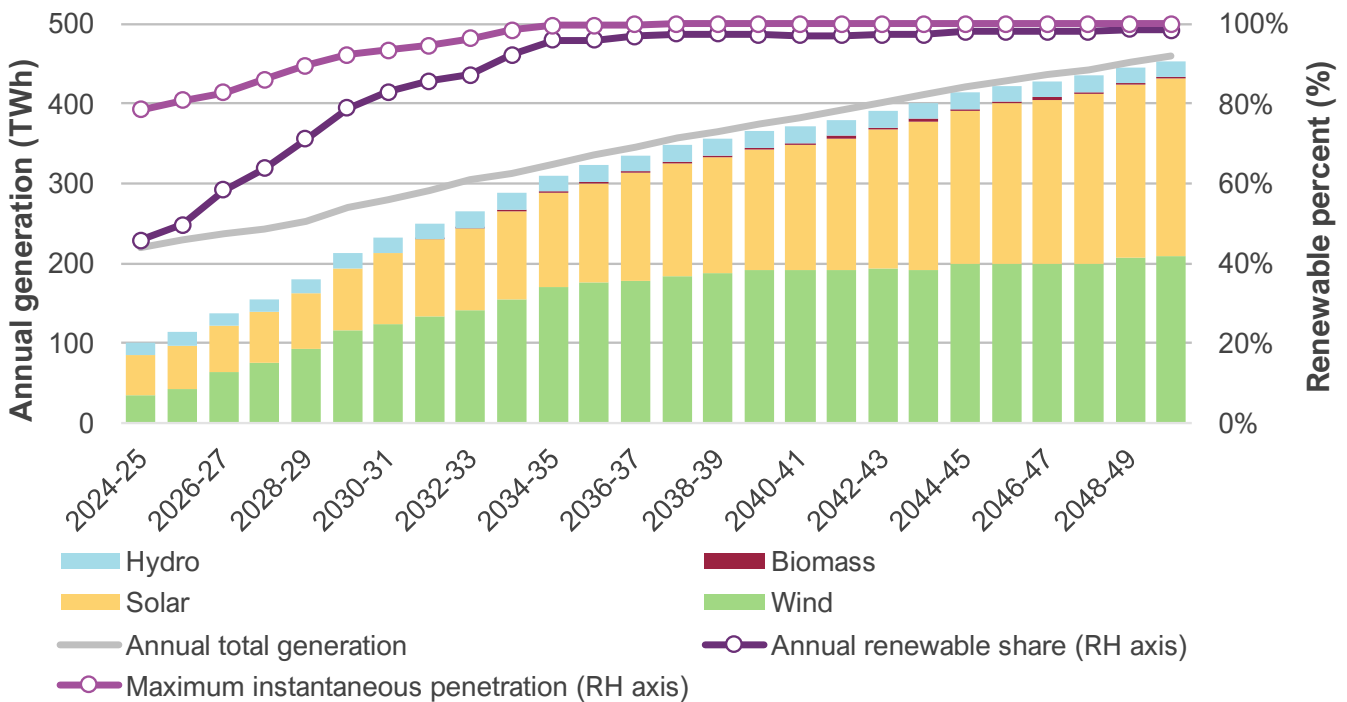


A4.3 VRE penetration and curtailment

AEMO’s *Engineering Roadmap to 100% Renewables* report² outlines AEMO’s plans to prepare for higher instantaneous penetration of VRE. In future, periods with sufficient potential VRE to meet 100% of demand will become more frequent, but operating the system securely and reliably with fewer large synchronous generators may be challenging without appropriate grid services. Continued investment in solar and wind generation will increase VRE capacity, and investments in storage will enable surplus generation to be used to meet demand when resources are less available, and investments in essential system services will also be critical to managing the high penetration of inverter-based resources.

Figure 4 shows forecast levels of annual total generation, annual renewable generation, and renewable share of total generation to 2049-50. Maximum instantaneous renewable penetration is forecast to reach 100% by the mid-2030s, with total underlying demand met entirely by renewable sources at certain times during the year.

Figure 4 Forecast annual renewable generation (TWh), annual renewable share of total generation and maximum instantaneous renewable penetration, 2024-25 to 2049-50, Step Change



TWh: terawatt hours.

The highest levels of instantaneous penetration of VRE will be limited by the commercial strategies of coal-fired generators to operate their generators, and the availability of sufficient power system services to maintain security of supply. Coal generators typically bid to maintain some level of operation in all periods, to avoid the high cost of starting and stopping their units. System security requirements for inertia and other system services also impact the requirements for synchronous generation. Given commercial and security requirements, it is forecast to be more economically efficient to ‘spill’ excess VRE generation than to build sufficient transmission and storage to allow all excess generation to be used or stored for future use.

² At <https://aemo.com.au/en/initiatives/major-programs/engineering-framework>.



VRE penetration

At the time of writing, NEM renewable resource potential³ has reached a high point at 99.7% of demand across a 30-minute period⁴. By 2025, it is projected that periods of over 100% renewable potential (when total available CER, hydro and utility-scale VRE generation exceeds forecast demand) will occur during lower underlying demand intervals. As renewables replace thermal generation, the range of renewable potential experienced by the NEM becomes higher and narrower, and 100% renewable potential occurs more frequently at higher underlying demand levels. Figure 5 shows the forecast changes to renewable resource potential relative to underlying demand from 2024-25 to 2049-50 in *Step Change*.

Periods where there is 100% renewable resource potential will not necessarily result in 100% instantaneous renewable penetration. Instantaneous renewable penetration levels are restricted by market behaviours, network constraints, system security requirements and distribution network considerations. Records for instantaneous renewable penetration, or share of total energy supplied from renewable sources have already surpassed 70%⁵. The 2024 ISP generation mix is only forecast to reach 100% instantaneous NEM penetration when the last coal units retire in the mid-2030s, or possibly earlier if seasonal withdrawal of coal capacity occurs.

Figure 5 Forecast renewable resource potential, 2024-25 to 2049-50, Step Change (GW)

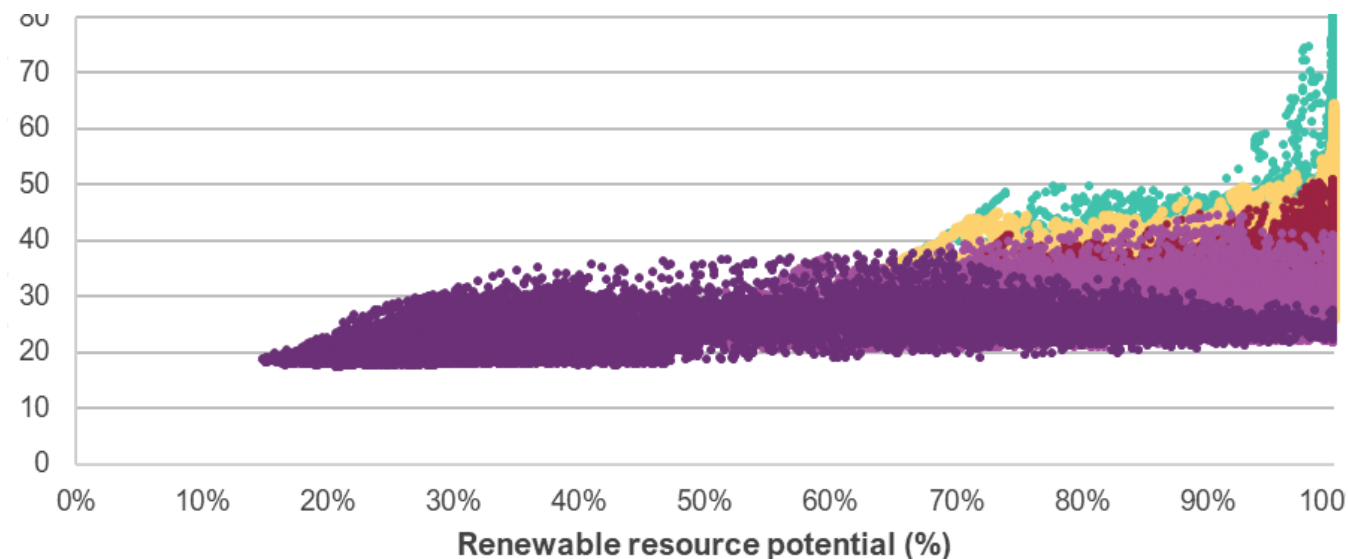


Figure 6 shows the distribution of renewable resource potential and penetration for every half-hour in 2019-20 (historical) and in forecast years 2024-25, 2029-30, 2039-40 and 2049-50. Renewable resource potential is projected to be sufficient to meet all demand occasionally by 2024-25 and around 25% of the time in 2029-30.

³ Renewable resource potential is defined as total available power from CER, utility-scale wind and solar, plus actual generation from dispatchable renewables.

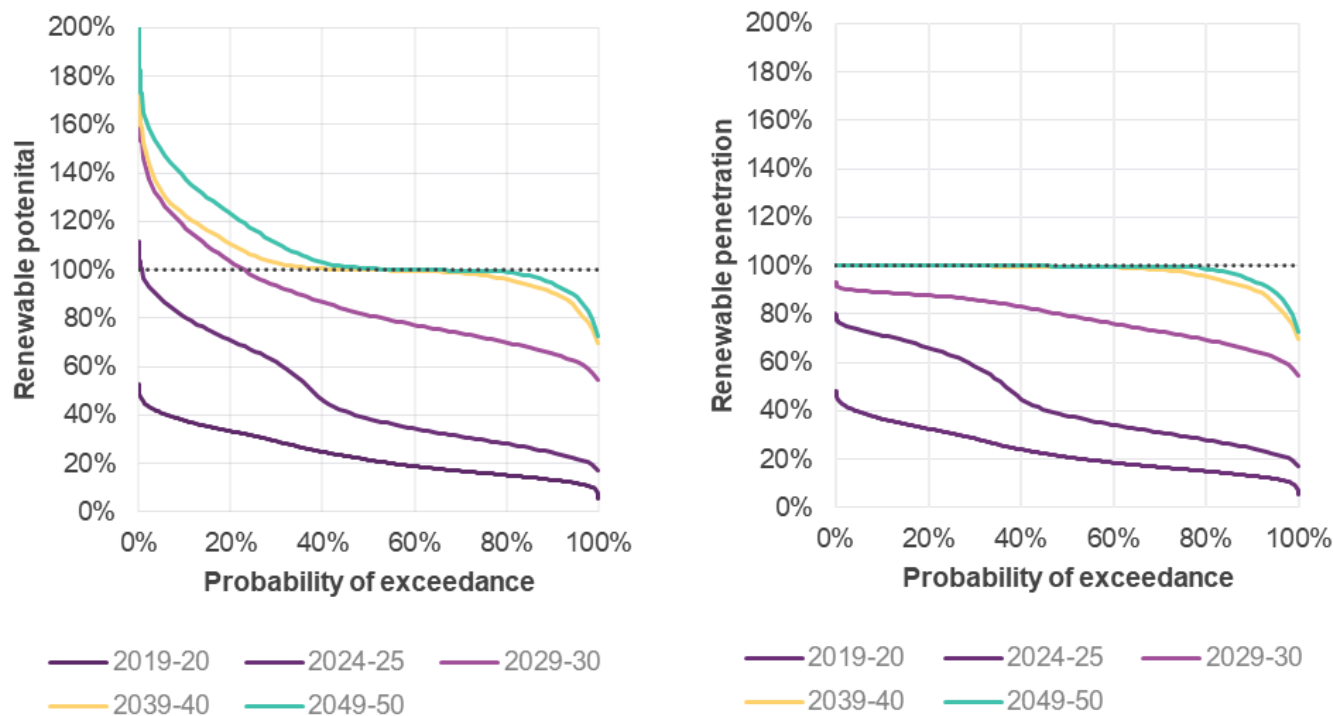
⁴ Observed on 1 October 2023. See AEMO *Quarterly Energy Dynamics* Q4 2023, at <https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf>.

⁵ See AEMO media release 23 October 2023, at <https://aemo.com.au/newsroom/media-release/renewables-push-nem-electricity-prices-down-to-historical-levels>.



In these years, continued operation of coal-fired generators prevents 100% instantaneous penetration from being achieved, even if renewable resource potential meets or exceeds electricity demand.

Figure 6 Distribution of forecast renewable potential (left) and penetration (right), 2019-20, 2024-25, 2029-30, 2039-40 and 2049-50, Step Change



Geographic diversity of VRE resources is delivered through developing new resources across the NEM, many of which will be within new renewable energy zones (REZs), as well as through network expansion to connect these new developments with customers across the grid. As a result, renewable resource potential is forecast to rise across nearly all half-hour periods during the year, especially between 2024-25 and 2039-40. Increased use of storage technologies will help shift excess daytime generation from periods of renewable energy surplus to times of lower VRE availability and will rely on appropriate storage management and storage depth to achieve this.

VRE curtailment

Modelling undertaken for the 2024 ISP forecasts instances where VRE generators will not operate at maximum potential capacity. There are a range of reasons for this, including:

- Periods when VRE resource potential exceeds demand, particularly at times of low operational demand.
- Insufficient transmission capacity to transport VRE to demand centres.
- Network security or other functional constraints for system strength or security.
- Lack of storage capacity to absorb the excess VRE generation.

These conditions may lead to economic ‘spill’ 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 2024 ISP forecasts that it is uneconomic to develop transmission and/or storage capacity to accommodate all peak VRE generation potential, meaning some degree of spill or curtailment is inevitable to keep total system costs as low as possible. As the seasonal load profiles diverge, generation development 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 spill or curtailment when renewable resources are higher.

Figure 7 shows the total VRE potential that is forecast to be utilised (generation) or not (spill and curtailment) out to 2049-50. As coal capacity closes and transmission is expanded, the level of available VRE spilled or curtailed is forecast to remain between 10% and 20% annually across the horizon.

The majority of unused VRE potential is the result of economic spill, rather than curtailment due to transmission limits⁶. High solar generation during spring and summer will lead to an oversupply of energy, some of which is forecast to be spilled.

Figure 7 Forecast VRE generation and spilled or curtailed energy 2024-25 to 2049-50, Step Change (TWh)

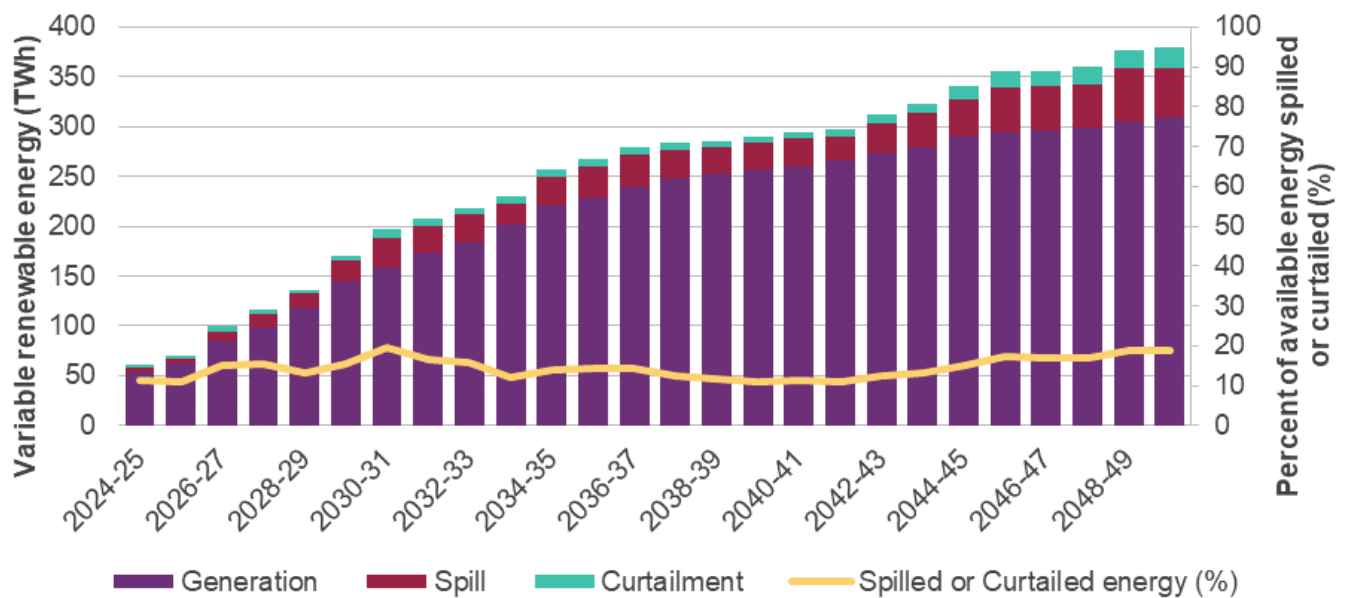


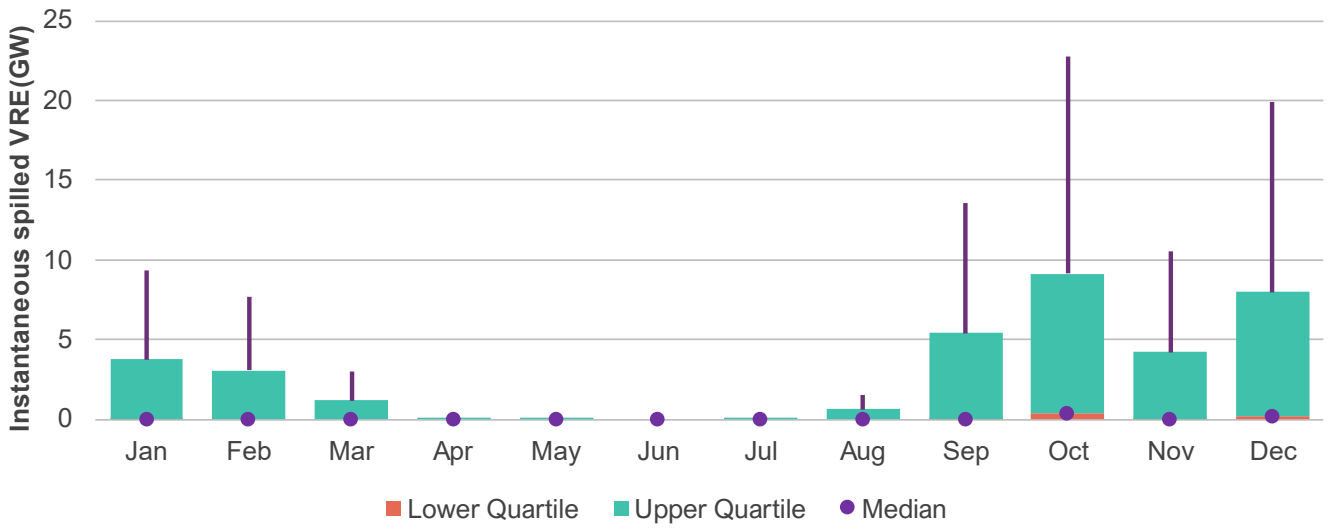
Figure 8 shows the forecast monthly distribution of instantaneous economic spill in 2039-40 across a range of weather reference years, and illustrates the months with excess energy generation potential.

The large majority of spill is projected to occur during daylight hours on sunny and windy days, with much more VRE spilled in December than in June. The reduced solar resource in winter may lead solar developers to target winter yields in their solar farm designs. The seasonal trend of VRE curtailment also indicates long-duration storages could have a key role shifting energy on a seasonal basis to provide strategic energy reserves. AEMO views this as an important role to be performed by deep-reservoir hydro (see Section A4.6, Figure 24 and Figure 25).

⁶ See Figure 6 in 2024 ISP Appendix 3.



Figure 8 Forecast NEM frequency of spilled VRE capacity in 2039-40, Step Change (GW)





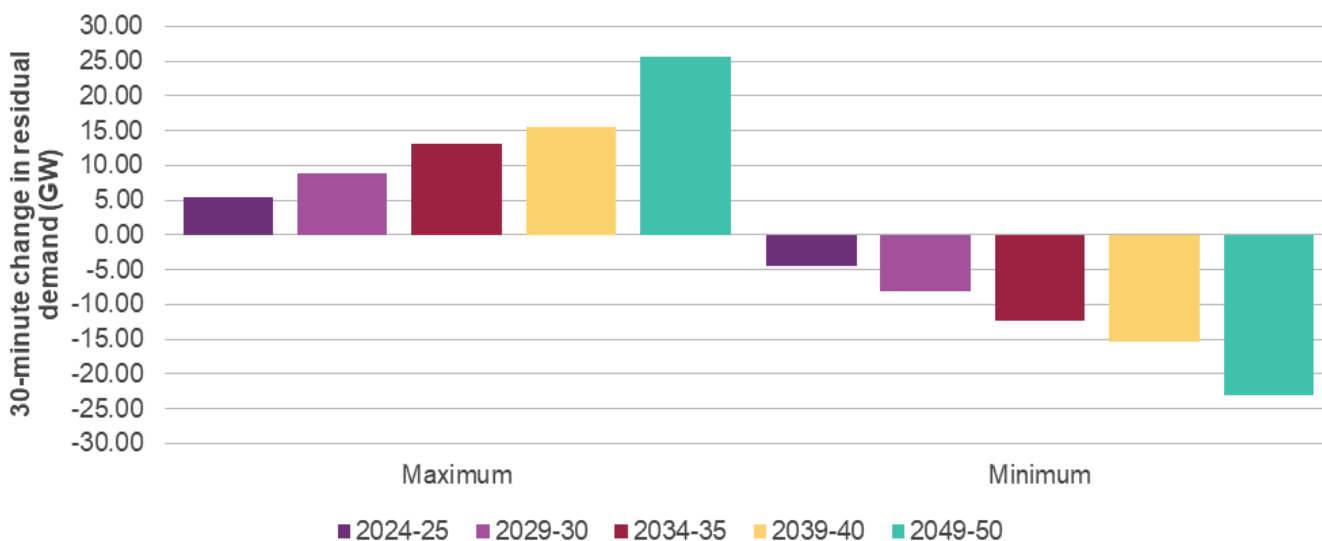
A4.4 System flexibility manages increased variability

Resource flexibility is required to manage increased variability of electricity generation and demand. Residual demand is the electricity demand to be met by dispatchable generation, in other words, demand net of VRE generation. Rapid and more frequent changes to residual demand across the power system will require sufficient ramping capability of firm resources 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 distributed PV due to localised cloud movements.

Managing the operational requirements of firming technologies, including consideration of real-time ramping requirements to support the variability of VRE and CER, will be important to operating the NEM securely and reliably.

During the period to 2049-50, residual demand that cannot be met by VRE technologies is forecast to reduce significantly but also become much more variable. Figure 9 below shows the maximum and minimum changes forecast in half-hourly residual demand over a year in *Step Change*.

Figure 9 Forecast maximum and minimum changes in half-hourly residual demand, 2024-25 to 2049-50, Step Change (GW)

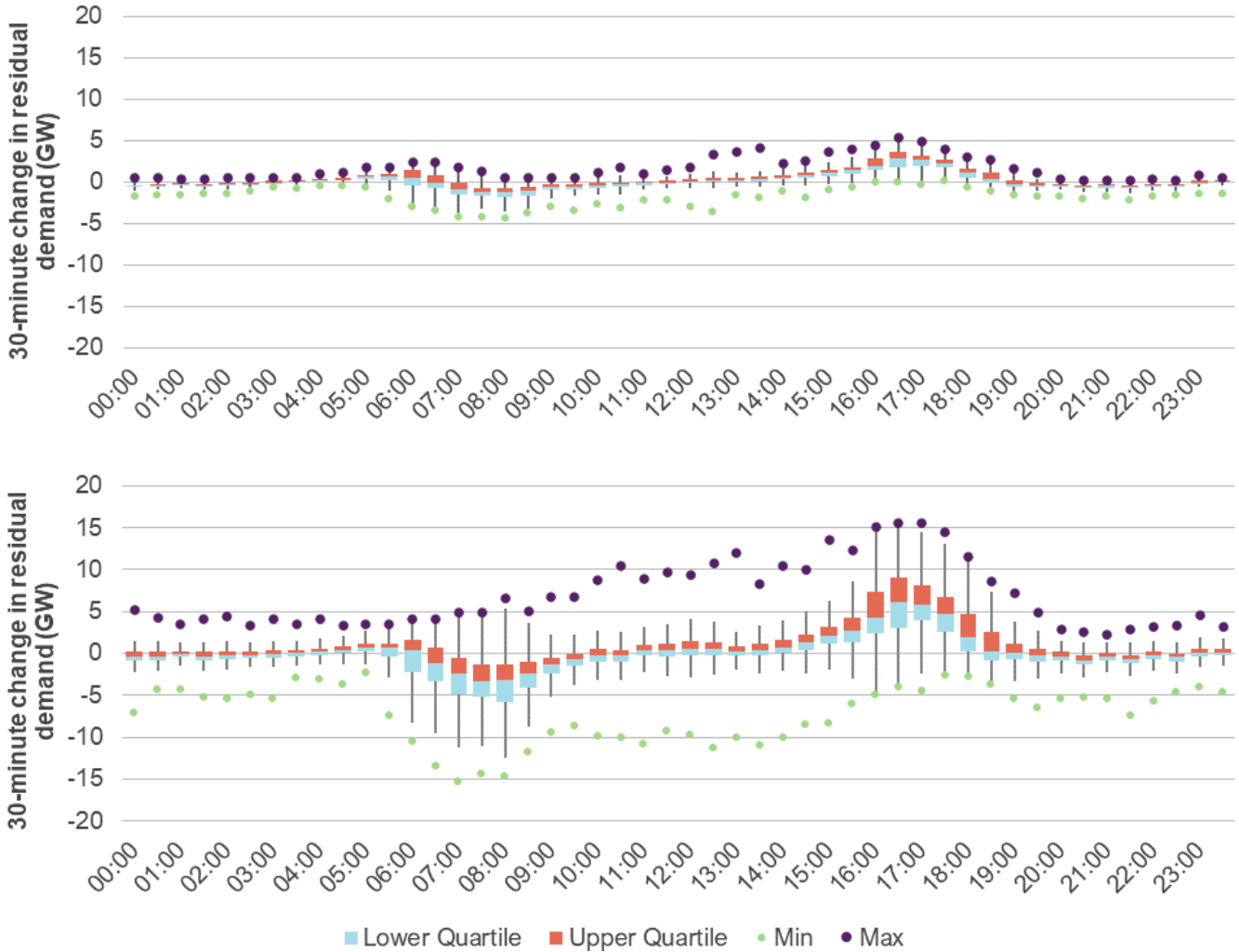


Residual demand fluctuations become more extreme as utility-scale and distributed solar capacity grows. While variations in wind generation also contribute to the need for ramping, wind speed fluctuations tend to impact generation from wind farms less due to greater resource diversity delivered geographically across multiple REZs. The periods of greatest changes are forecast to be at dawn and dusk as it follows the solar generation profile which is highly predictable and thus less challenging for NEM operations.

Figure 10 shows the forecast distribution of residual demand changes for each half-hourly period over the course of a day in 2024-25 and 2039-40.



Figure 10 Forecast time-of-day distribution of half-hourly NEM residual demand changes, 2024-25 (top) and 2039-40 (bottom), Step Change (GW)

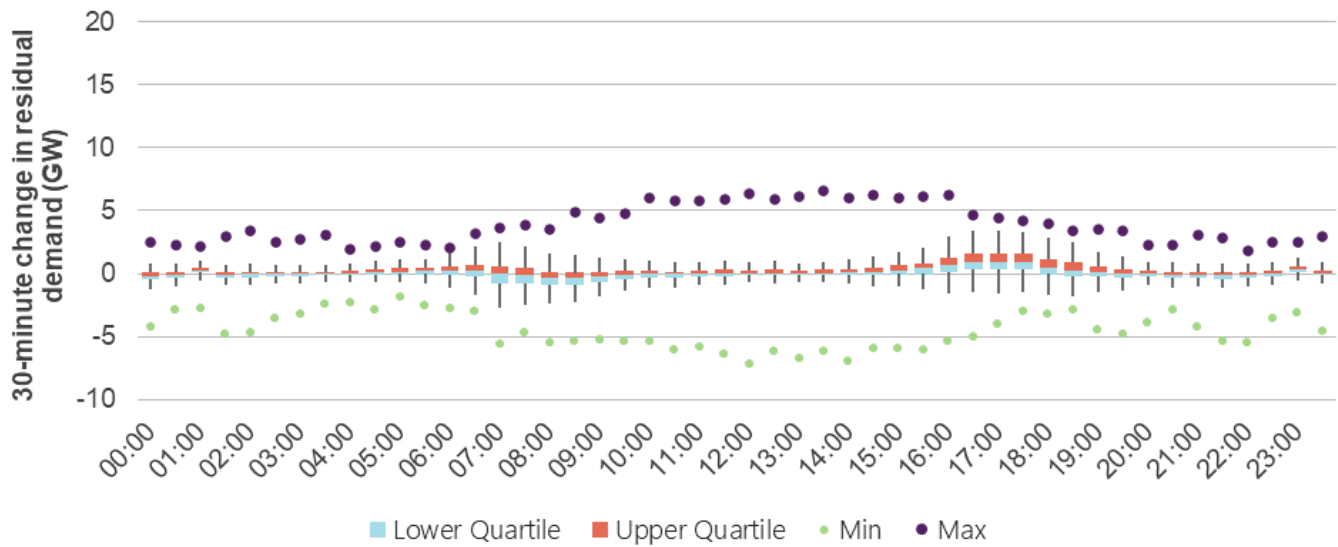


Smaller and less predictable changes to residual demand at other times of the day are expected to present a more significant challenge to future NEM operations.

Figure 11 shows the forecast variability for Victoria, demonstrating an example where a large distribution of ramp up or down requirements is forecast during the middle of the day as a result of fast-changing weather patterns affecting wind and solar generators between 1000 hrs and 1600 hrs.

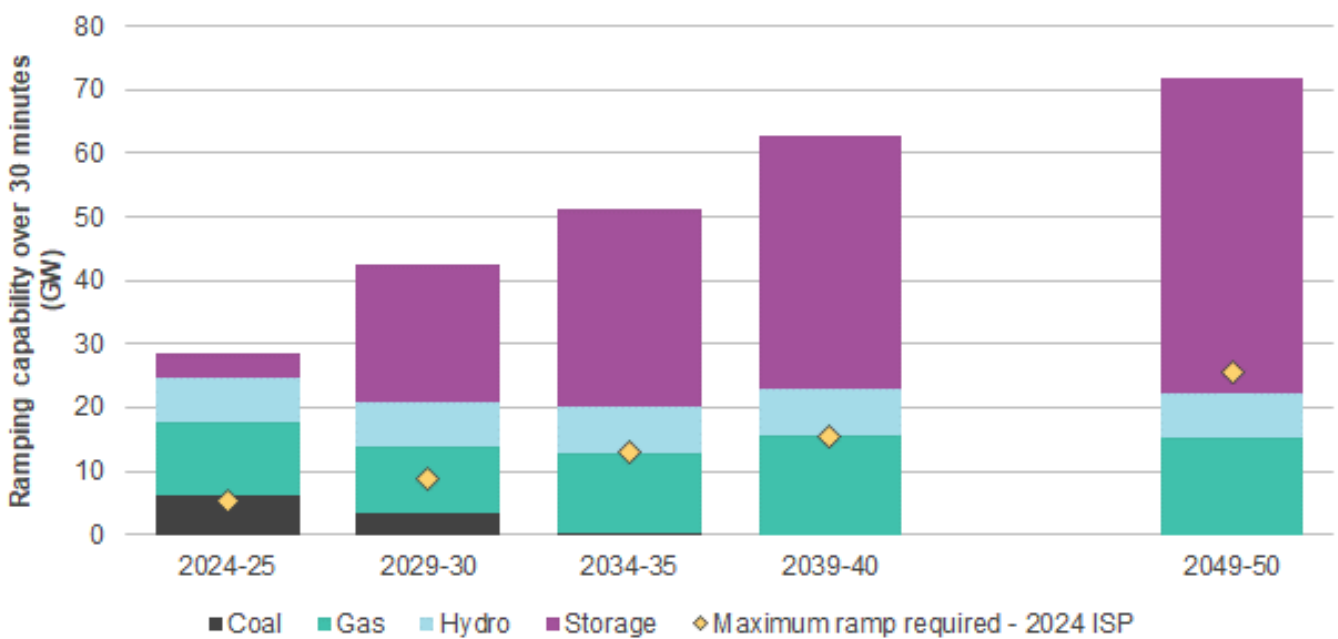


Figure 11 Forecast time-of-day distribution of half-hourly residual demand changes in Victoria, 2039-40, Step Change (GW)



In the future, grid-scale and distributed storage devices (including pumped hydro) are forecast to become the primary providers of system flexibility, but GPG and hydro will continue to provide significant ramping capacity. Figure 12 shows the projected maximum ramp up capability in gigawatts for each 30-minute period across the dispatchable generation fleet. The 2024 ISP ODP is forecast to develop firm capacity throughout the forecast horizon to match growing demand and balance VRE intermittency and availability. During daily operation, the actual ramping capacity of a unit will vary according to online status, current generation, and, in the case of storage, the level of stored energy at that time.

Figure 12 Forecast maximum ramping capability of dispatchable generation, 2024-25 to 2049-50, Step Change (GW)

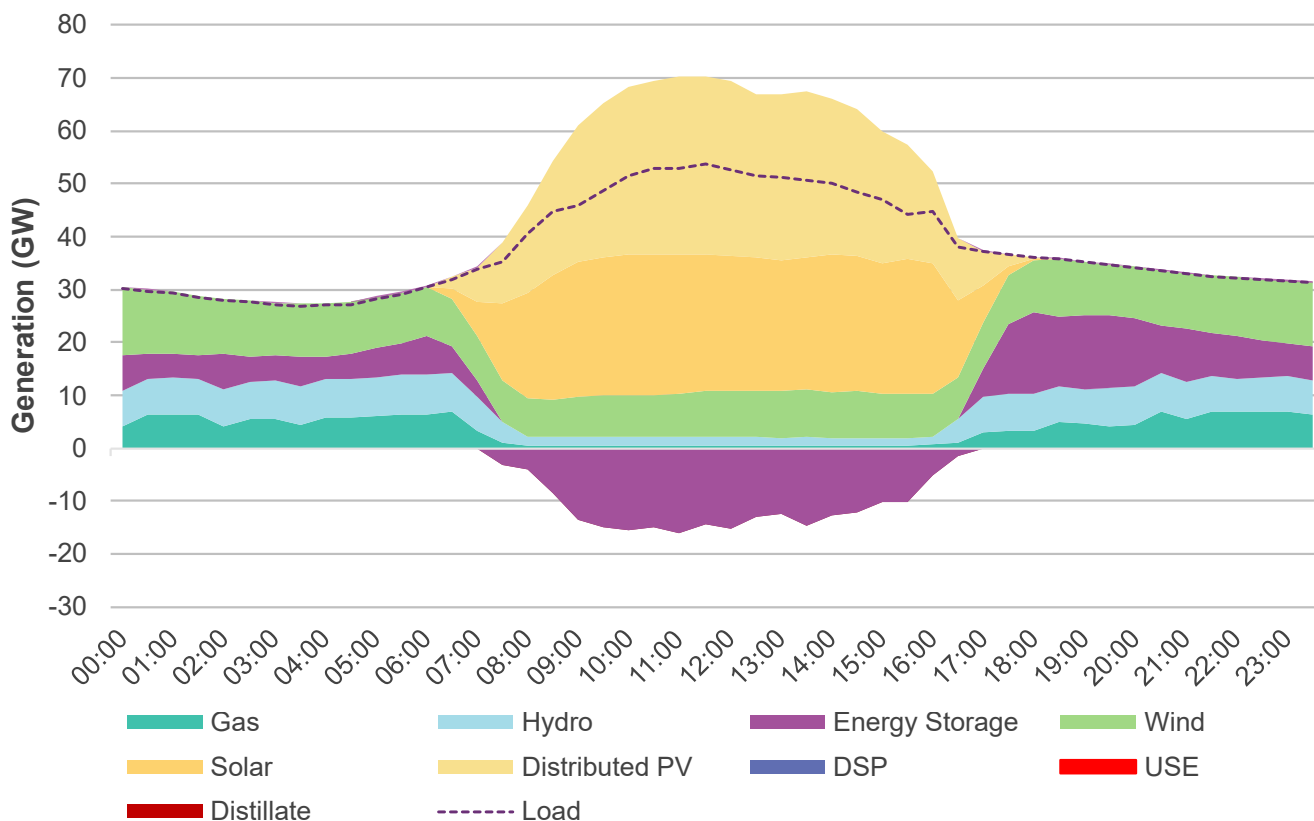


Note: Biomass, diesel, and hydrogen generators are aggregated into the Gas category.



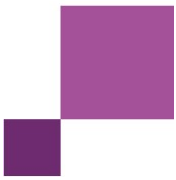
Figure 13 presents the forecast NEM generation mix during a day in 2040 when a peak 15 GW ramp up equivalent to 40% of underlying load is required at approximately 1700 hrs due to significant generation reduction from solar when load remains relatively high. Storage technologies contribute most of the ramping required by rapidly discharging stored energy, with gas and hydro generators providing the rest of the ramping requirement. In cases where stored energy and other dispatchable generation is insufficient to meet demand, demand side participation (DSP) and demand response may need to be deployed.

Figure 13 Forecast NEM generation mix on a day with maximum ramp in 2040, Step Change (GW)



Storage dispatchability is forecast to become crucial to the reliability and security of the power system. Therefore, market settings that incentivise storage operators to reserve energy for discharge during high demand periods will be important. Periods of VRE scarcity when demand is relatively high will typically elevate market prices and encourage storage operators to reserve adequate ramping capability. Further discussion on the topic of storage dispatch behaviour to firm up supply-demand variations is in Section A4.6.

This assessment does not address maintaining grid security and the provision of critical frequency and voltage control services. Appendix 7 provides more detail regarding system security and engineering requirements for secure operation of the power system.



A4.5 Operating the power system during long, dark, and still conditions

Resilience during VRE droughts

The NEM must be resilient in its capability to provide energy in all weather conditions, including when there is minimal or no sunshine or wind for prolonged periods. The 2024 ISP ODP delivers resilience during long, dark and still periods through a geographically and technologically diverse mix of generation, supported by flexible gas generation and storages of various depths. Transmission augmentations enable the transport of electricity from regions with excess generation to regions experiencing tighter VRE supply conditions.

The 2024 ISP forecasts the storage capacities needed to complement VRE developments and provide dispatchable and firm sources of supply. The development of medium and deep storages is important to complement GPG and hydro generators, providing the capacity to store energy and dispatch it over long periods.

During longer and more severe VRE droughts, energy reserves in storages may become depleted and GPG may be required to generate at full capacity. During these periods, ensuring sufficient fuel supply – both via gas system infrastructure and on-site storage of secondary fuels – will be essential to maintaining reliability. Section A4.8 explores the limitations of the gas system to deliver fuel to GPG and analyses the operation of on-site liquid fuel storages to manage fuel constraints during these operationally challenging periods.

Storage definitions

- **Consumer-owned storage** (or distributed or CER storage) – behind-the-meter household, business or industrial batteries, including EVs that may be able to send electricity back into the grid. Coordinated CER storage is managed as part of a VPP, while passive CER storage is not.
- **Shallow storage** – grid-connected storage to dispatch electricity for less than four hours, valued for both their system services and their energy value.
- **Medium storage** – to dispatch electricity for four to 12 hours. This may be battery or pumped hydro (or other emerging technologies in future) which can shift large quantities of electricity to meet evening or morning peaks.
- **Deep storage** – strategic reserves that can dispatch electricity for more than 12 hours, to shift energy over weeks or months (seasonal shifting) or cover long periods of low sunlight and wind (renewable droughts), backed up by GPG.

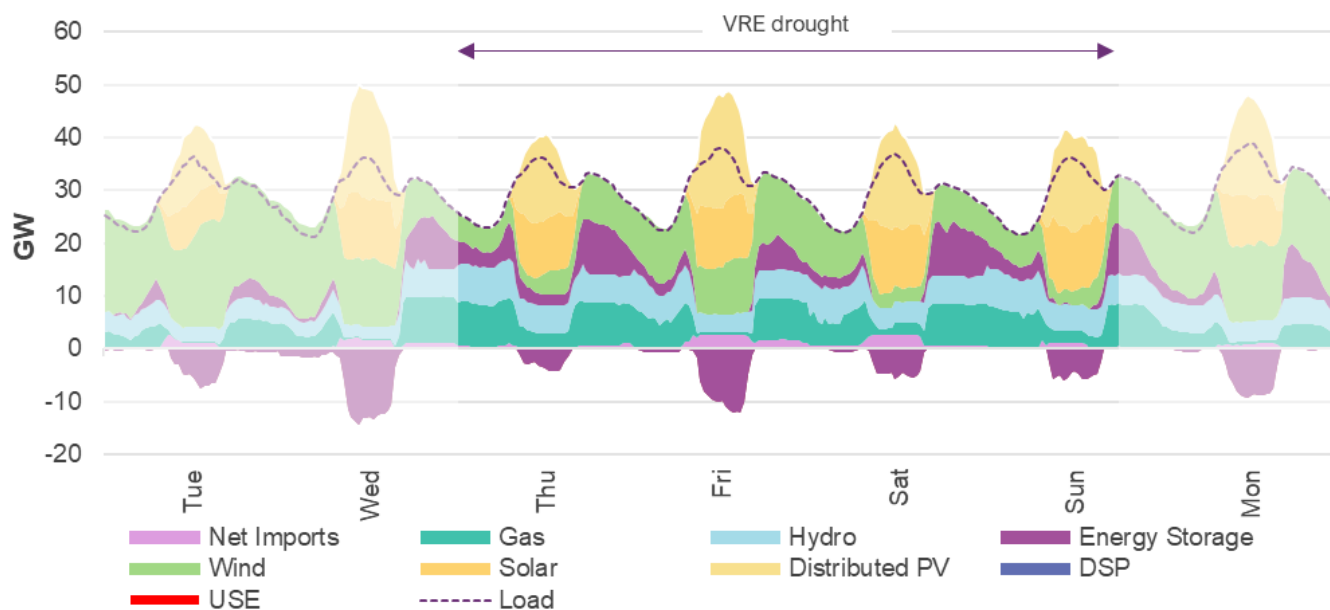
Long, dark and still conditions typically can last for hours or a whole day but are problematic for system operability on the rare occasions they persist for multiple days. These weather conditions are most likely to occur during winter and cause longer VRE droughts when lower solar generation coincides with still wind conditions. In a system with high levels of VRE, the resulting energy shortage may cause reliability risks if sufficient firming resources are not available for dispatch. Delivering geographical diversity of generation and firming resources is a strong benefit of the transmission expansions forecast in the ISP and will improve system resilience.

By 2040 in *Step Change*, all coal-fired power stations are forecast to be out of service and generation in the NEM will be dominated by VRE and CER with firming provided by storage, hydro and flexible gas. With these resources,

the NEM is forecast to operate reliably through similar⁷ and even more severe VRE droughts observed in recent history⁸.

Figure 14 shows the forecast dispatch mix⁹ in June 2040 during a severe VRE drought event, based on a historical severe dark and still weather event observed in June 2019. It shows southern regions (New South Wales, Victoria, South Australia, and Tasmania) experiencing extremely high residual demand due to low wind production. Queensland is experiencing stronger VRE availability during this time but the ability for Queensland to export surplus generation is limited by the capacity of the transmission system.

Figure 14 Forecast operability across the NEM (excluding Queensland) experiencing a three-day low VRE period in June 2040, Step Change (GW)



In this VRE drought event, the forecast for June 2040 shows that:

- Southern states experience high heating loads and relatively low VRE availability due to still, cloudy, and cool weather conditions across these regions.
- The VRE drought observed lasts for approximately three days in a row from Thursday to Saturday in the above example, with low solar production and relatively low wind output. On these days, GPG and hydro are required to run almost continuously at peak output to cover the VRE shortfalls.
- During this event, the gas system may become constrained to deliver sufficient gas to operate GPGs if there is coincident high gas demand. Detailed modelling and analysis on this topic is presented in Section A4.8.

⁷ Recent VRE low events in April and May 2024 showed extreme low wind productions across southern states. However, the solar outputs were still relatively high. As new solar capacity is forecast to increase in the future, the severity of the effects of these recent wind droughts is similar to the example conditions explored in this section.

⁸ AEMO's ISP modelling applied weather patterns from 2010-11 to 2021-22 and analysed the operability of the power system during future conditions, modelled off the historically observed weather. This analysis has indicated that historical average wind speeds (back to 1980) show a similar average wind speed and comparable spread of both extremely high and extremely low wind events.

⁹ Distillate (diesel), biomass, and hydrogen are aggregated in the Gas category.



- Sustained support is provided from hydro resources in New South Wales and Tasmania, made more accessible by transmission augmentations.
- Surplus VRE from Queensland contributes to meeting demand via the upgraded Queensland – New South Wales Interconnector (QNI, shown as Net Imports in Figure 14). In addition, net imports from Queensland are sometimes required to help fill southern storages during the middle of the day.
- Shallow and medium storages recharge during the days to dispatch during the afternoon peaks. However, during the days with the lowest VRE output (Thursday and Saturday), these storages will not fully recharge. Deep storage is therefore critical in shifting energy stored from days, weeks or months prior to the shortage to dispatch during these days.
- Stronger wind conditions in northern New South Wales assist on most days, enabling the filling of energy storages to meet evening load.
- Some voluntary DSP may be expected to reduce the magnitude of the peak demand periods.

NEM resilience through prolonged VRE droughts

The timing, severity and duration of prolonged dark and still weather conditions over a wide area are difficult to forecast, and indications are that these events are very rare. AEMO's modelling was based on 12 years of weather data covering a broad range of weather patterns, but it is not guaranteed that this historical period includes the most severe possible VRE drought conditions that may occur in the future. Climate conditions are expected to change over coming decades across the diverse regions of the NEM.

To anticipate the possible effects of these changes, AEMO has performed exploratory modelling to test the resilience of a power system dominated by VRE to prolonged VRE drought events. In the absence of reliable predictions of future weather conditions, algorithms have been applied to historical data to extend the duration of observed extreme weather conditions to simulate a more volatile future climate. This 'what-if' analysis simulated an extended period of low VRE conditions, extending a three-day event to eight days in duration. This approach retains the inherent internal consistency between supply, demand, and transmission models by using historical weather rather than future synthetic weather patterns.

Figure 15 shows the forecast dispatch mix during this extended VRE drought event running from 21 June 2040 to 28 June 2040 (reflective of conditions observed historically in June 2019), showing the extended drought period plus the preceding and following days. The NEM is projected to operate all available dispatchable resources (predominantly deep storages and gas) to meet the high residual demand, and shallow and medium storages are critical in shifting energy to meet the afternoon peaks.

Figure 16 shows there is projected to be insufficient spare generation to fully recharge all shallow and medium storages (consumer batteries including VPPs, and utility-scale storages) on these days. These storage facilities must operate at lower capacity or for shorter periods during the most severe five days (from 21 June to 26 June).

Deeper storages are simulated to enter the renewable drought period at around 70% state of charge¹⁰, reflecting energy that has been stored from previous days or weeks. With this level of stored energy and considering the

¹⁰ AEMO modelling assumed weather forecasts provide reasonable notice prior to this event and therefore storages are sufficiently charged in advance.



capacity to refill reservoirs on these days, energy storages are drawn down by approximately 10-15% state of charge each day. It is very important that alternative technologies are developed to complement storages – the role of GPG and demand response in these conditions is critical.

Figure 15 Forecast operability across the NEM (excluding Queensland) experiencing an extended eight-day VRE drought, June 2040, Step Change (GW)

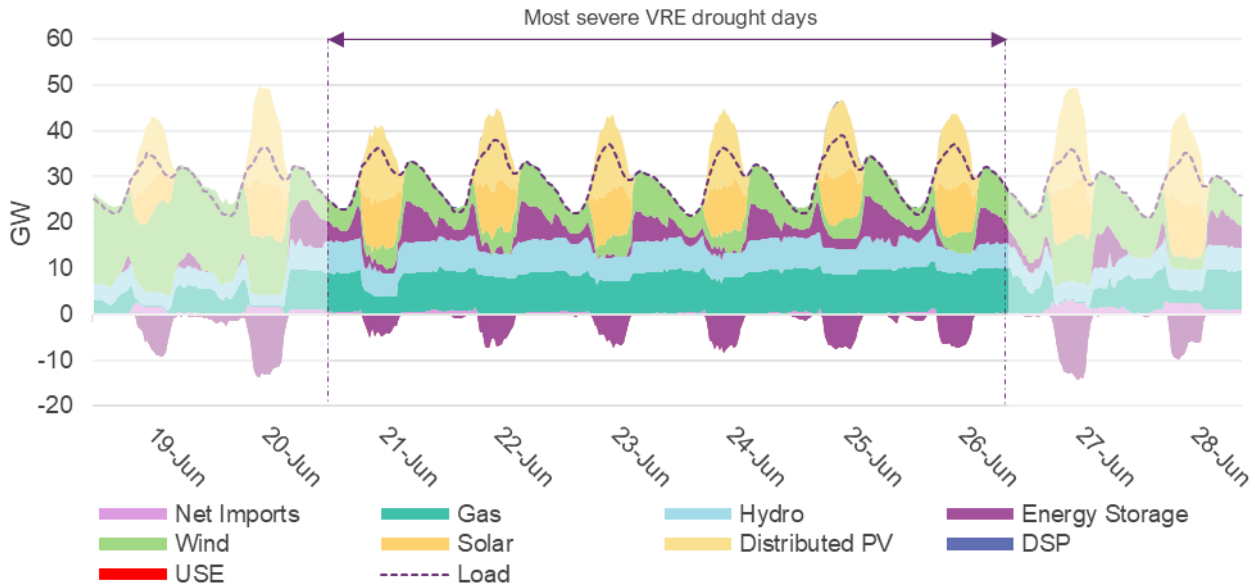


Figure 16 State of charge of shallow, medium and deep storage in southern states during a forecast extended eight-day VRE drought, June 2040, Step Change

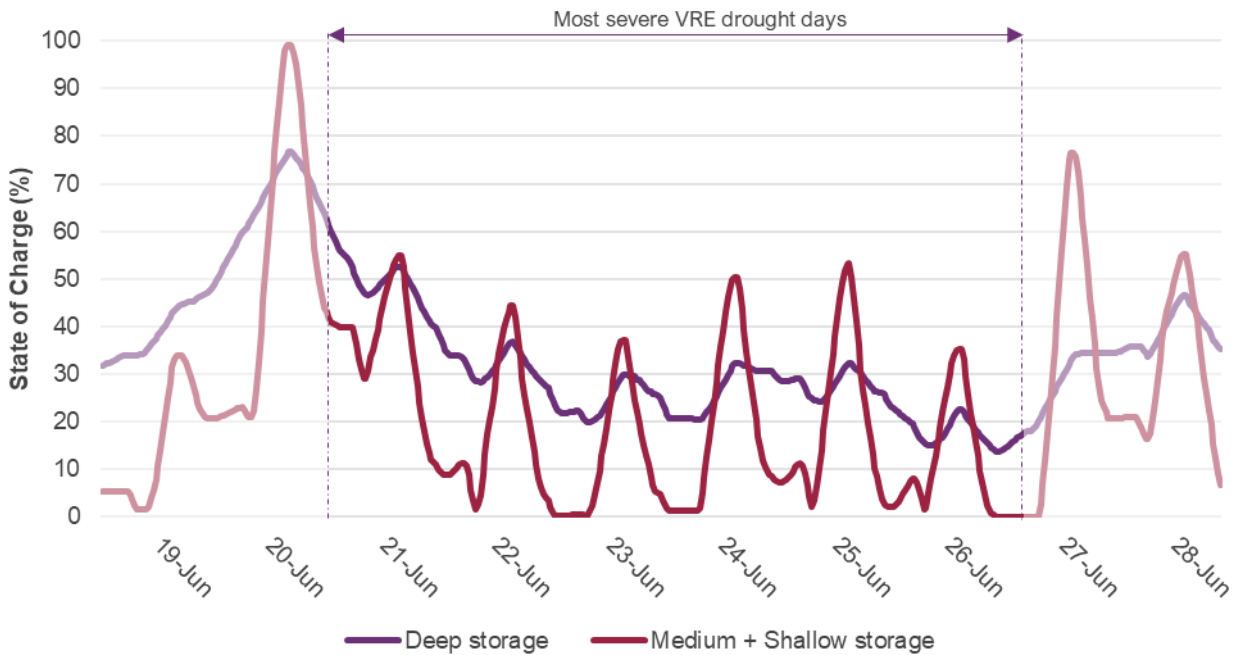
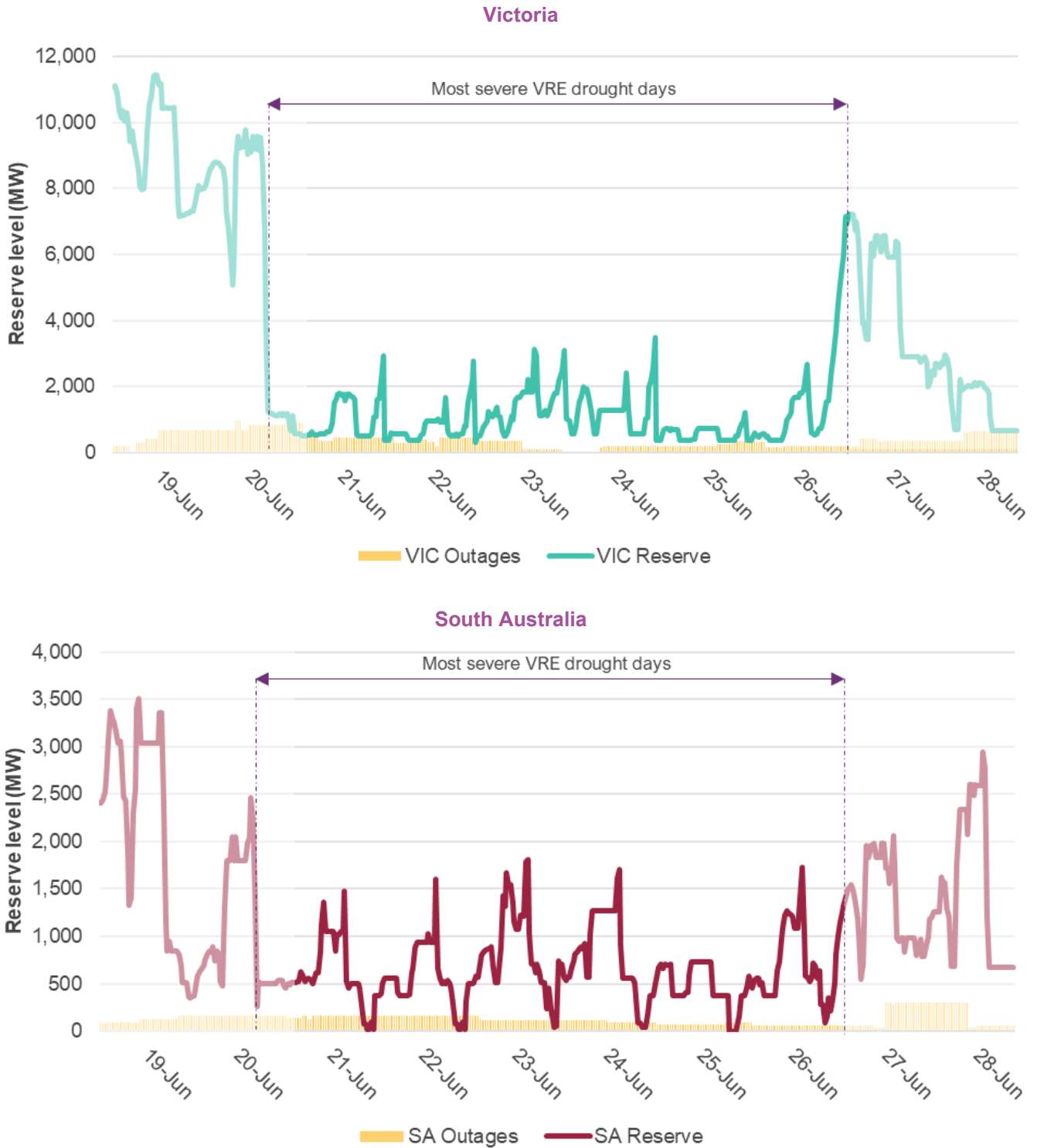


Figure 17 shows Victoria and South Australia are forecast to be operating on very thin reserve margins, so if a coincident major contingency event occurs both states would be at additional risk of experiencing USE.



Figure 17 Reserve level (MW) in Victoria and South Australia during an extended eight-day VRE drought, Step Change (MW)



Note: Reserve level refers to the available dispatchable generation capacity and demand response in a region plus the region's import headroom. Interconnector support is estimated as the maximum energy supply available to the region from neighbouring regions' surplus generation.



This analysis suggests the 2024 ISP ODP is resilient to VRE droughts with sufficient cover from storages, GPG and hydro generation to service low renewable conditions that have been artificially grown to levels more significant than observed historically. Although high prices are likely and voluntary DSP may be used in this example, the NEM is forecast to be capable of operating reliably through droughts two or three times longer than historically observed. In this simulated test of extreme weather resilience, no USE was forecast, although any additional unplanned outages beyond those modelled may cause reliability concerns.

To minimise the risks posed by extreme VRE droughts and maintain reliability, AEMO modelling indicates the need for:

- Fuel supplies to be available for flexible gas to operate at maximum capacity for prolonged periods. This will require greater fuel diversity with on-site storage of secondary fuels. More detailed modelling and analysis on this topic is presented in Section A4.8.
- Weather forecast accuracy will influence the degree of foresight of extended dark and still weather to allow accumulation of sufficient energy (or water) in deep storages prior to periods of VRE drought. While careful management of shallow storages would be required during these conditions, the availability of deep storages to efficiently supply the load centres most at risk is important to ensure resilience to these unpredictable periods. More detailed modelling and analysis on this topic is presented in Section A4.6.
- Maintenance schedules of dispatchable generators need to be carefully managed and coordinated during winter when VRE droughts are more likely to occur.
- Strategic reserves in dispatchable capacity, and energy reservation of deep storages, may be required to provide appropriate resilience to forecasting errors, imperfect foresight, unavailability risks and fuel supply risks.

NEM resilience to severe droughts during periods of high underlying demand

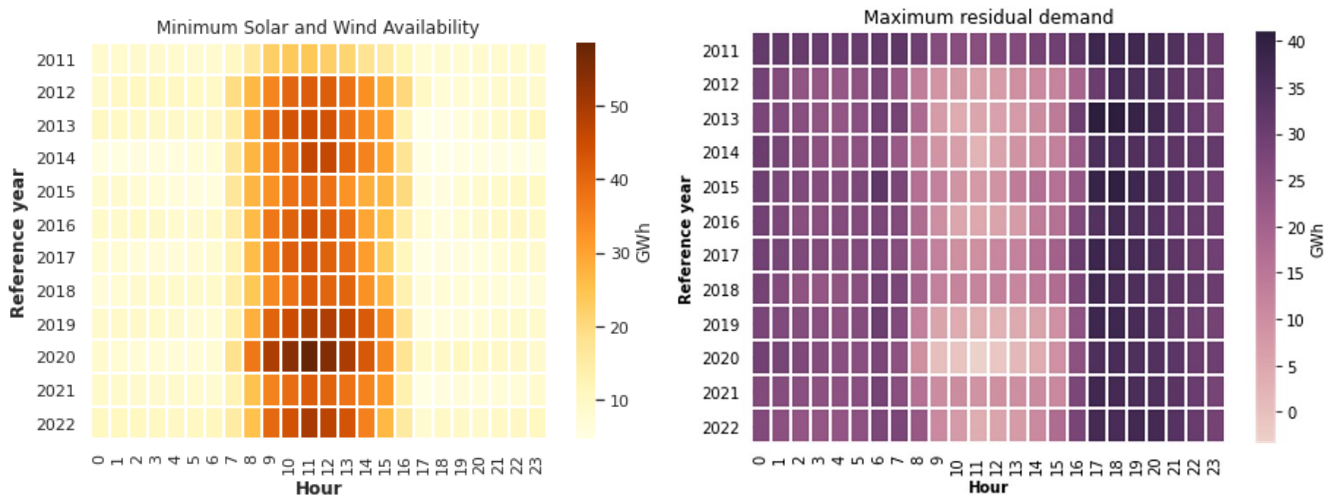
Following the closure of all coal generation, VRE is forecast to provide the bulk of the NEM's electricity supply, meaning that the power system will be increasingly exposed to weather variations. The ongoing reliability of the power system will require firming capacity to match the full range of variations in VRE supply in duration and magnitude. Southern regions are particularly exposed to VRE volatility during winter, given the lesser number of daylight hours, and the greater requirement for heating loads that are forecast to electrify, thereby amplifying the risks of low VRE conditions coincident across solar and wind technologies.

Across the modelled historical weather conditions in AEMO's ISP, by winter 2044-45 in the *Step Change* scenario, daily solar and wind production can vary between 1,450 gigawatt hours (GWh)/day (roughly 115% of underlying demand) to as low as 350 GWh/day (dropping to only 35% of underlying demand). This highlights the value of transmission to deliver uncorrelated VRE resources to neighbouring regions, which will reduce the amount of local dispatchable capacity in the form of storage or gas required to be built.

This is illustrated in Figure 18, which shows the extent of VRE and residual demand variation considered within ISP modelling in all regions over winter 2044-45.



Figure 18 Minimum solar and wind availability (left), and maximum residual demand (right), across NEM regions over winter 2044-45, across 12 simulated reference weather years



Note: Reference years are expressed in terms of financial years; for example, the 2011 reference year implies the 2010-11 historical weather year.

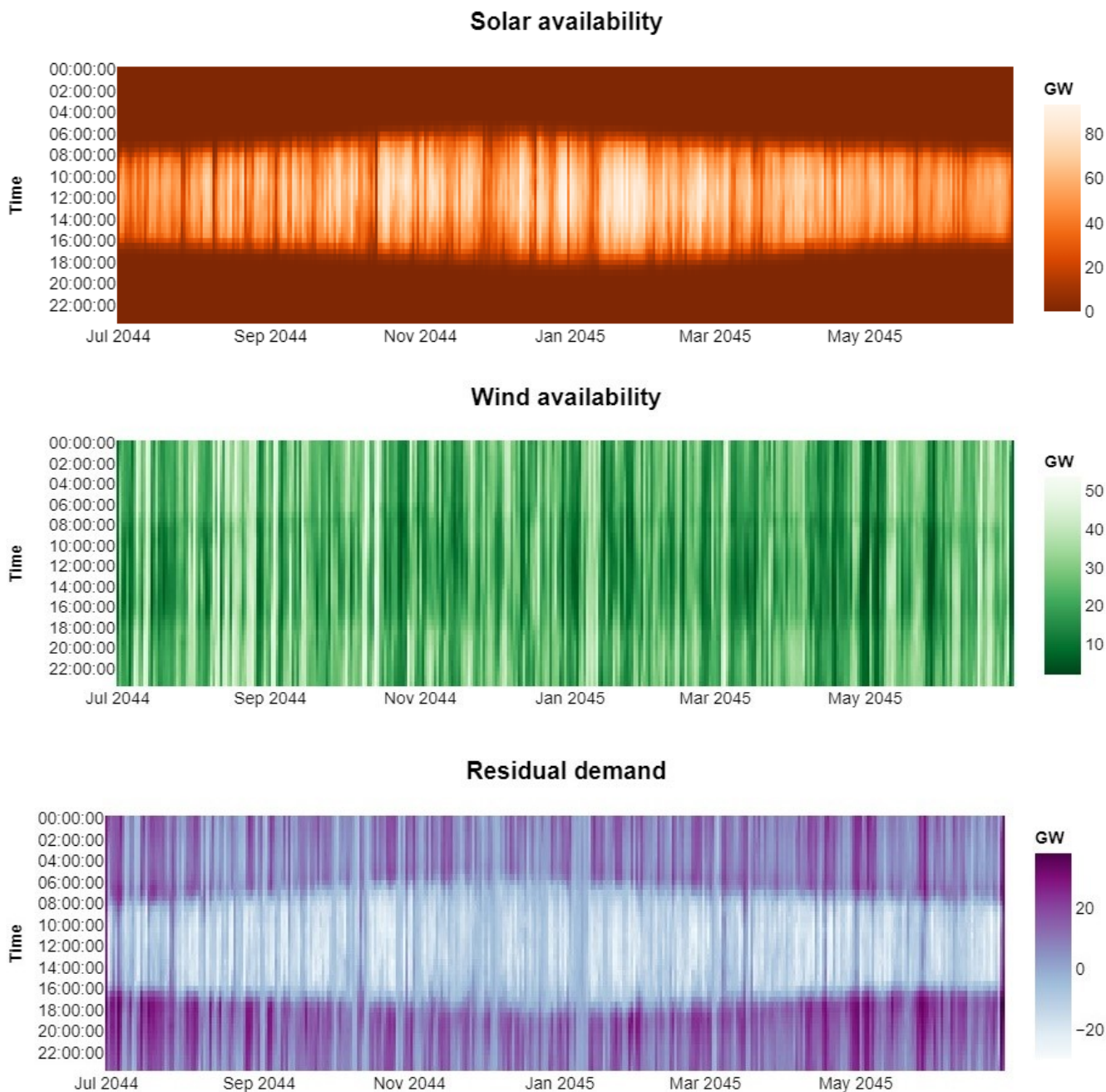
The 2011 weather reference year (representing weather conditions observed across the year between July 2010 and June 2011) features extremely low VRE coincident with periods of high underlying demand. This results in prolonged days of high residual demand.

Figure 19 below shows heat maps of NEM-wide solar and wind availability, and residual demand for 2044-45 using the 2011 weather reference year. The charts show:

- Solar output is low during short days in winter, although these effects are confined to daytime hours only.
- Wind availability is more unpredictable, with multi-day lulls possible across all seasons of the year, and at all hours of the day. Lulls in wind availability are more impactful during evenings when operational sent-out demand peaks and solar output ends. The geographical diversity of wind resources provides some system protection, whereby southern regions experiencing windy conditions can support periods of low wind in the north, and vice versa. During more severe and prolonged NEM-wide low wind conditions, the system is supported by dispatchable technology such as storage and gas.



Figure 19 Heat map of solar (TOP) and wind (MIDDLE) availability, and residual demand (BOTTOM), during 2044-45, for the 2011 weather reference year



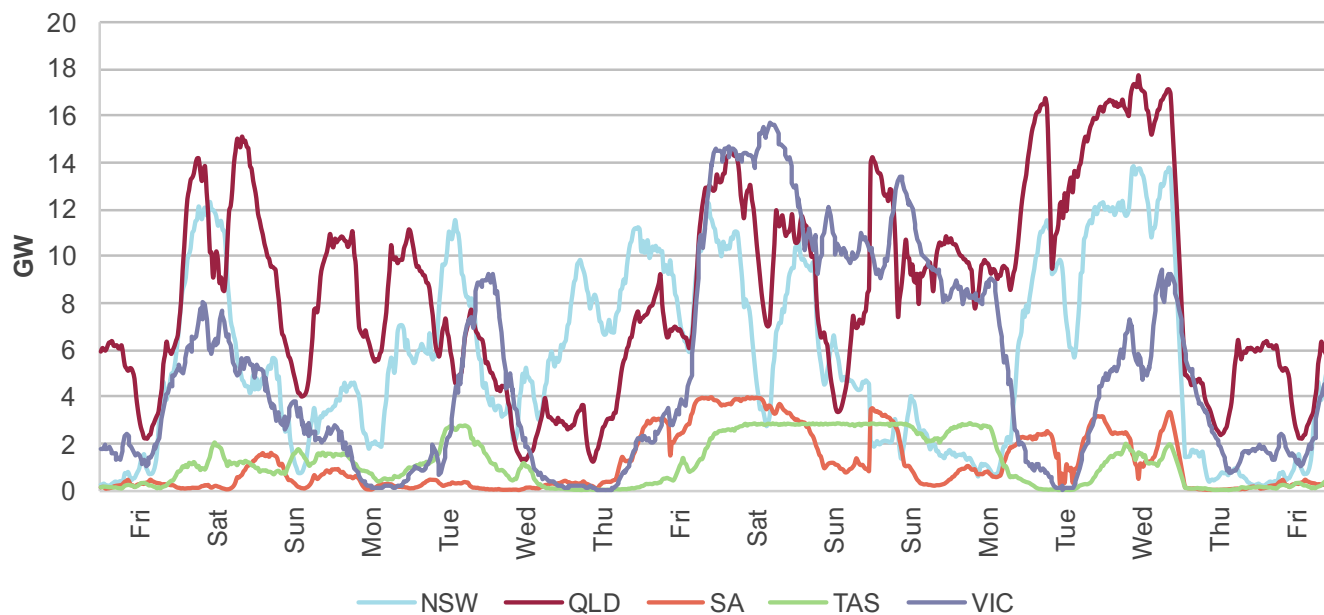
For example, the most operationally challenging period is forecast in the middle of winter in both winter seasons of 2044-45 (July 2044 and June 2045) during sustained days of very low wind and low solar generation across the NEM. Low VRE is particularly prominent during days of peak underlying demand in New South Wales and in Queensland.

As shown in Figure 20, wind production can be highly volatile, including sudden reduction in resource availability, as simulated at the end of June 2045 across all NEM regions.



During this period NEM-wide residual demand stays elevated above 25 GW for multiple continuous 24-hour periods. The 2024 ISP ODP forecasts around 12 GW of dispatchable medium and long-duration storage and 18 GW of non-storage technology from flexible gas generation (supplied from natural gas, biomass and hydrogen) will be required to provide critical firming support through these VRE lulls.

Figure 20 Wind production (GW) across regions from the beginning of July and end of June in 2044-45 in the 2011 weather reference year, Step Change



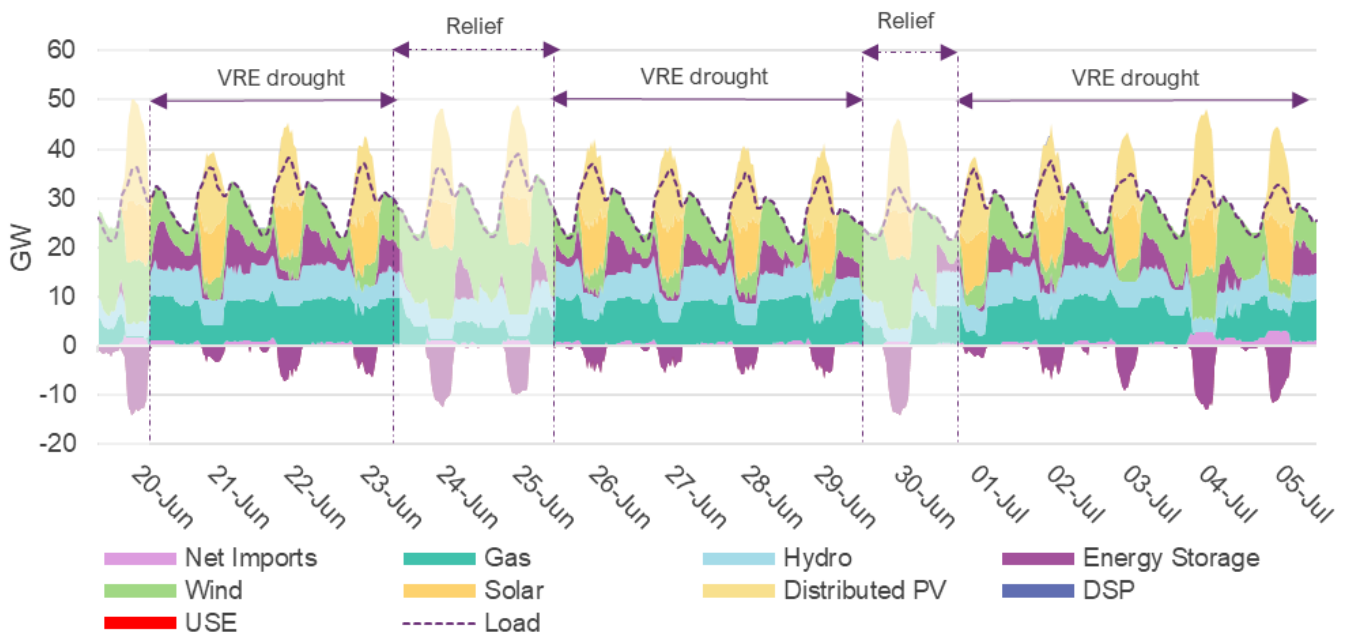
NEM resilience through multiple intermittent VRE droughts

Prolonged instability in renewable output may also occur over longer periods when multiple intermittent extreme weather systems affect generation in the NEM. AEMO has modelled a ‘what-if’ scenario by simulating multiple periods of unstable VRE output punctuated by brief periods of normal VRE generation.

Figure 21 shows the forecast dispatch mix over a two-week period in July 2040 when multiple VRE drought events are simulated to occur (12 days of low VRE in total), with intermittent periods where VRE recovers to average levels of energy generation (three days in total). The system is forecast to operate reliably during this extended period of weather instability by relying heavily on GPG and potential demand response on days of insufficient VRE production.

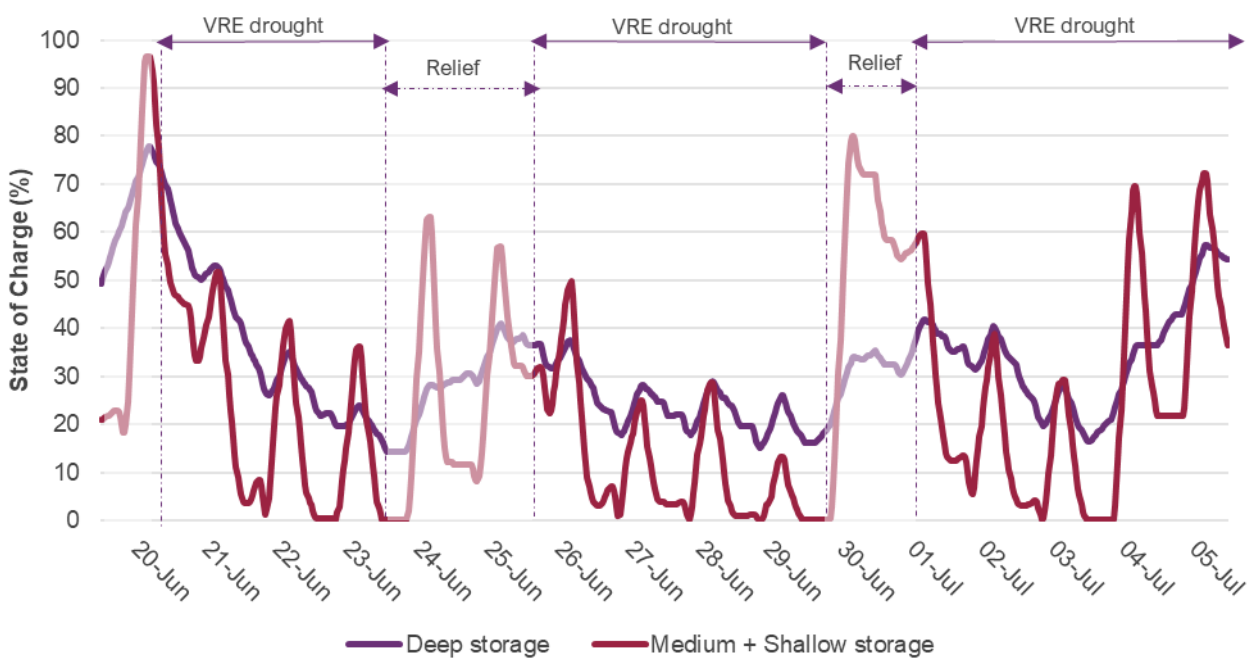


Figure 21 Forecast operability across the NEM (excluding Queensland) experiencing multiple VRE droughts, June-July 2040, Step Change (GW)



On days when VRE yields revert to average conditions, storages may be charged up to 40% (for deep storage) or 80% (for medium and shallow storage) in preparation for the next low VRE incidents (Figure 22). In addition to providing energy to storages, these days of average VRE production would critically allow gas generators to turn down (or off) and allow gas supply infrastructure to replenish gas storages and take delivery of secondary fuels to replenish on-site liquid storages.

Figure 22 State of charge of shallow, medium and deep storage in southern states during a two-week horizon with multiple VRE drought events, June-July 2040, Step Change



A4.6 Storage technologies will firm VRE

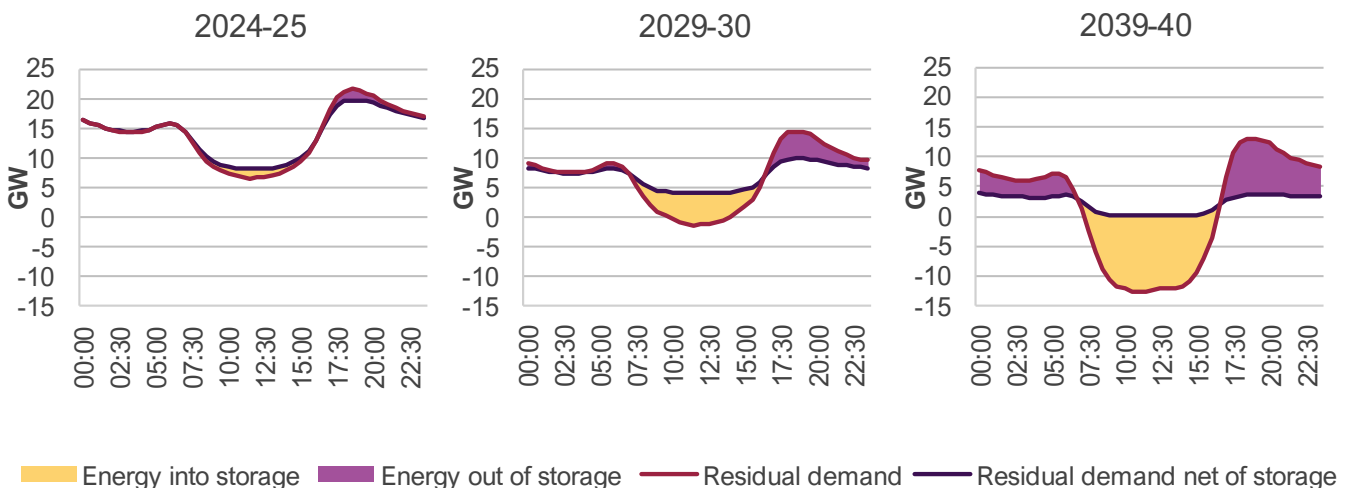
Storage technologies of different types and depths will provide a range of services in a NEM dominated by VRE. Storages currently provide load shifting, system balancing and active power reserves, in addition to advanced power system services such as synthetic inertia and system strength support. As the installed capacity of batteries in the NEM increases, operational strategies will shift away from providing system services and towards providing energy arbitrage. This section demonstrates the important role of energy storage systems in supporting the future operation of the power system, from an energy arbitrage perspective.

Shallow and medium duration storages provide intra-day load shifting

The NEM will increasingly rely on shallow and medium duration storages to provide intra-day load shifting. Storages participating in energy arbitrage will charge when low-cost, surplus daytime VRE is plentiful to be available to discharge fast-response ramping services and firming generation during peak demand periods as needed, when prices are higher. This reduces more regular dependence on alternative firming technologies such as flexible gas and hydro generation.

Figure 23 shows the forecast evolution of time-of-day average profiles of residual demand and the growing impacts of storage technology. As wind and solar (utility-scale and CER) penetration increases and coal-fired generators retire, residual demand is forecast to decrease and feature deeper daytime troughs. Forecast increases in storage capacity and depth will enable greater volumes of surplus energy to be time-shifted to service evening demand peaks over longer durations. Storages will also help smooth the evening residual demand peak, allowing generators with less flexibility to operate at a flatter profile.

Figure 23 Forecast time-of-day average profile of residual demand, Step Change, 2024-25, 2029-30 and 2039-40 (GW)



Long-duration storages provide seasonal energy security

While short- and medium-duration storages such as batteries will increasingly provide intra-day firming for VRE, deep storages and hydro-electric facilities with deep water reservoirs (such as Lake Eucumbene in New South Wales and Lake Gordon in Tasmania) will provide a strategic reserve by allowing energy to be stored and shifted seasonally to support longer periods of low VRE generation, particularly if market settings encourage this behaviour.

Figure 24 shows the forecast 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, but more volatile during winter months.
- Residual demand is higher during winter, due to higher underlying heating load and reduced solar output.
- Operation of seasonal energy storages and GPG are forecast to become more winter-focused to support lower solar output and more volatile wind output, but may still have a critical need during extreme demand days during summer.
- Battery and pumped hydro storages operate consistently, but cycling¹¹ is maximised during periods with greater daily fluctuations in residual demand which create stronger arbitrage opportunities.

Figure 24 Generation mix and maximum monthly residual demand, *Step Change*, 2039-40

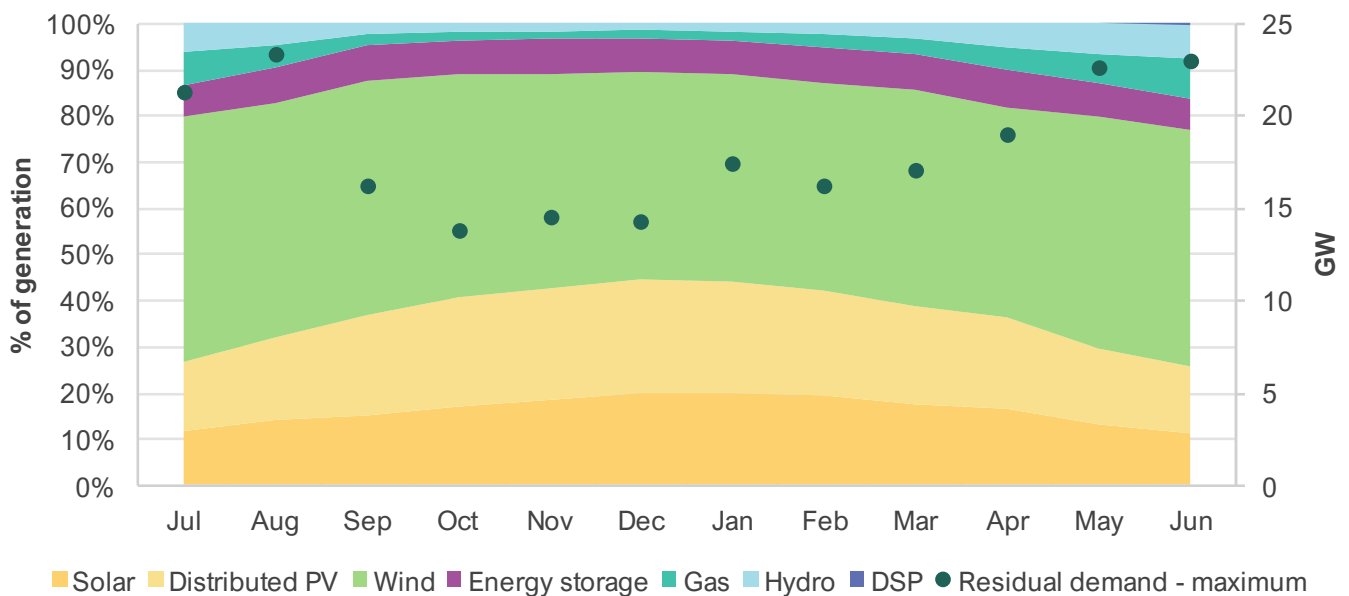


Figure 25 shows how the forecast seasonal pattern of energy stored in deep storages including pumped hydro and hydro-electric reservoirs changes over the periods between 2024-25 and 2049-50 in *Step Change*. In the near term, modelling indicates hydro storages will dispatch into intervals of summer peak demand and accordingly store lower amounts of energy over warmer months. Over time, the monthly profiles of energy stored in deep reservoirs shifts from depleting over the summer towards holding energy into early winter. As thermal generators exit and VRE capacity increases, hydro will need to play an important deep storage role, supporting the system through longer periods of high residual demand that are more prevalent during winter months.

¹¹ As batteries and pumped hydro charge and discharge electricity, the level of stored energy cycles between low and high levels.

Figure 25 Daily energy forecast to be stored in deep storages and hydro reservoirs over a year, *Step Change* (GWh)

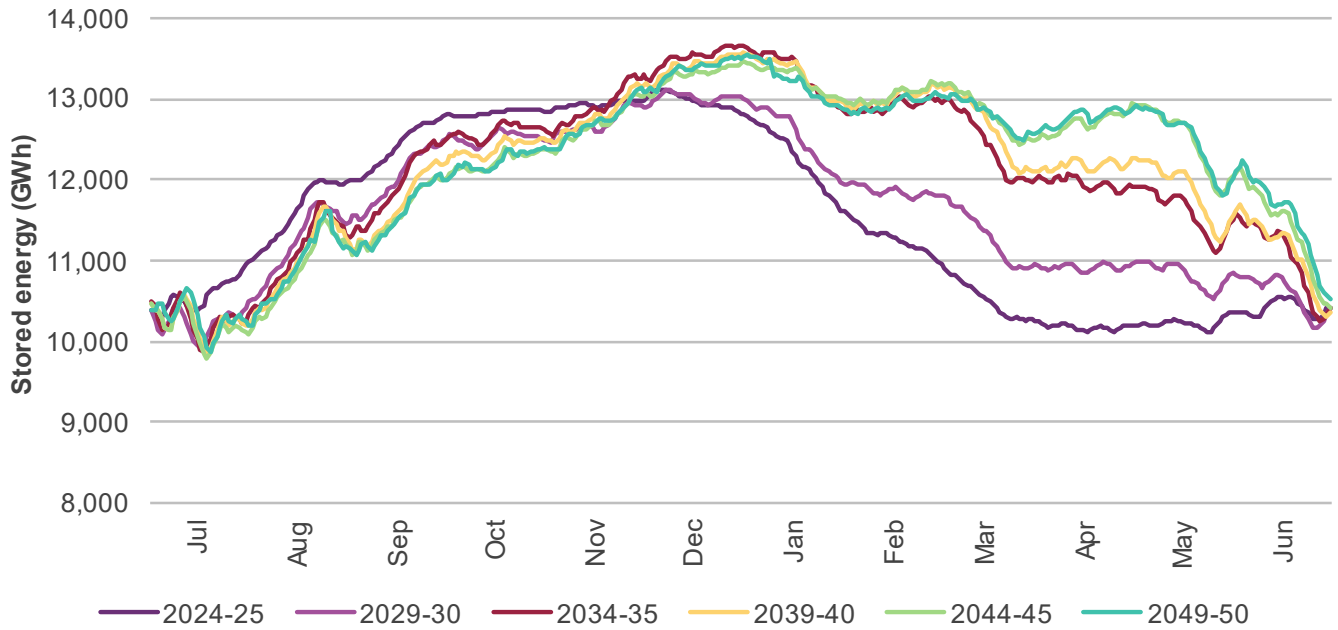
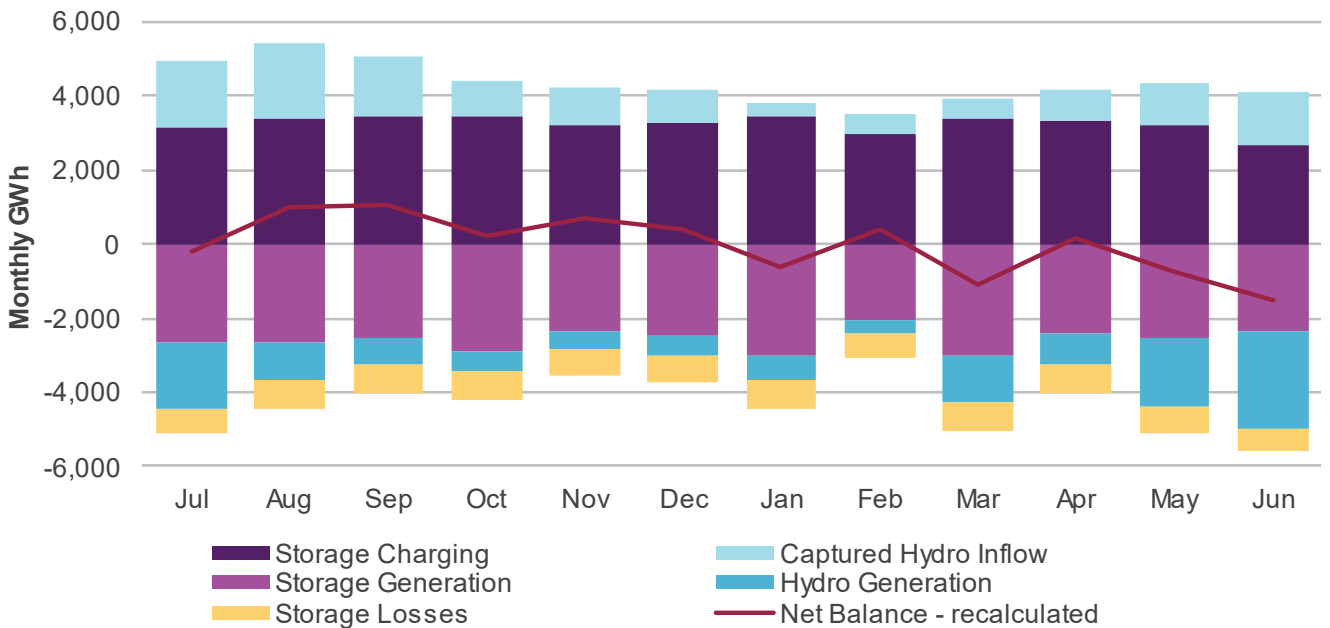


Figure 26 shows the *Step Change* 2039-40 forecast for monthly energy discharged and used to charge (or fill) energy storages (battery and pumped hydro), in comparison with deep hydro reservoirs. Positive values represent total energy flowing into storage during the month, while negative values represent total discharge. A positive net balance indicates storages generating more energy than inflows received.

Figure 26 Forecast monthly energy balance of storage (shallow, medium, and deep) and hydro, *Step Change*, 2039-40 (GWh)



Deep hydro-electric storage reservoirs in southern alpine regions are typically replenished by snowmelt over springtime and rainfall over wetter months. Pumped hydro technology can utilise VRE surplus in summer to return water to higher elevations then discharge this over the autumn and winter months when residual demand is higher. Shallow and medium storage technologies will provide more intra-day and inter-day shifting to meet peak demand. If appropriately utilised, shallow storages (including VPP devices) can reduce the reliance on deeper storages to operate frequently, enabling the deeper storages and hydro reservoirs to reserve more energy for weekly, monthly or seasonal energy shifting.

The forecast shift for hydro storages towards being winter-discharging will require consideration of irrigation management and assessment of flooding risks. During winter 2022, hydro-electric generation was high to compensate for high unavailability of coal generation, but prior wet years had saturated dam catchments which constrained generation from the Snowy Hydro scheme¹². This highlights that coordination between hydro operators and water authorities will be necessary at times to realise the full potential of hydro generation for seasonal energy shifting, and that externalities to energy models will exist that mean broader strategic reserves and deep storage will improve system resilience to unpredictable conditions.

Impact of imperfect foresight of battery operation

AEMO's energy market modelling is optimised with the benefit of various degrees of foresight of VRE output and operational demand within each simulated day. This enables a near-perfect management of the state of charge and enable efficient energy arbitrage operations for shallow, medium and deep storage technologies, and CER storage technologies. Actual energy storage operation involves imperfect foresight, so AEMO has examined imperfect foresight in more detail to ensure time-sequential modelling outcomes are representative.

Figure 27 compares the modelled dispatch profile of shallow storage large-scale batteries against actual performance during 2021-22, illustrating that the modelled optimisation of shallow storage based on current observed behaviour tends to overstate utilisation of energy storage dispatching into evening peaks. This is in large part due to these storages prioritising provision of frequency control ancillary services (FCAS) over time-shifting of energy and is not representative of how storages may behave in the future.

As storage becomes more prominent in the energy market, lack of foresight as to when high price events will occur may cause shallow storages to discharge before the time of maximum value or retain energy for future periods when the market opportunity is perceived to be greater. AEMO has considered several modelling approaches in time-sequential modelling for the 2024 ISP to examine the impact of this potential issue.

¹² See Australian Energy Regulator (AER), State of the Energy Market 2022 report, at <https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202022%20-%20Full%20report.pdf>.

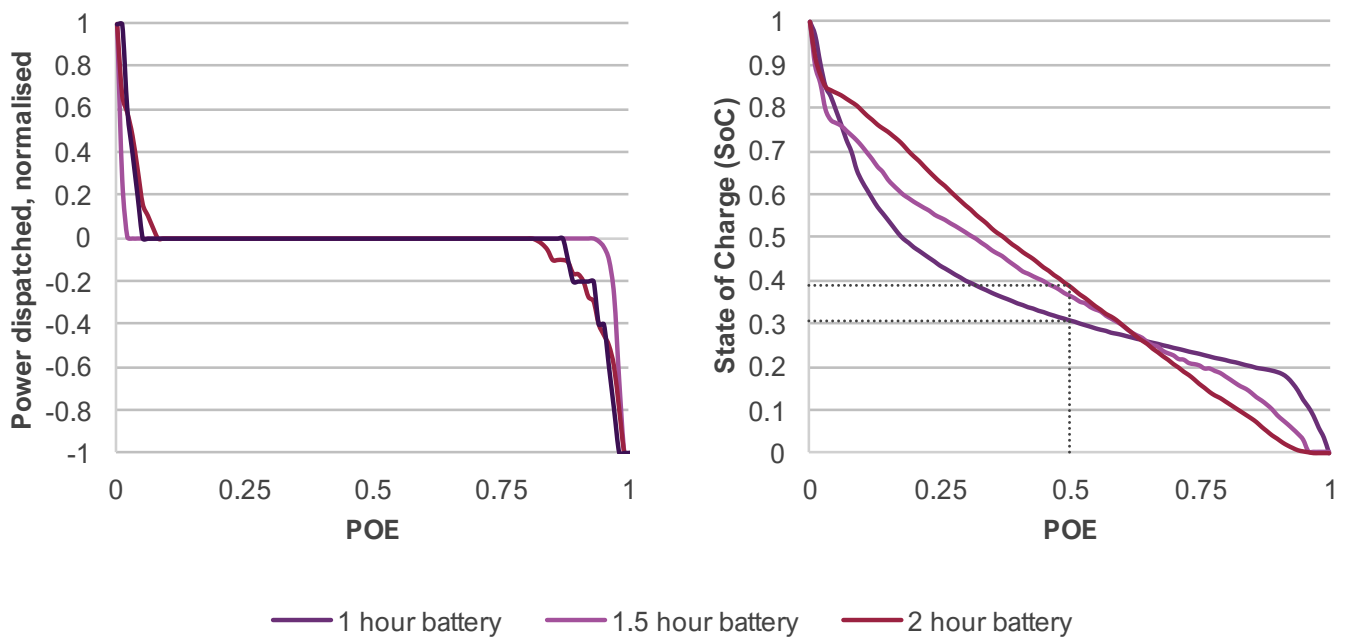
Figure 27 Actual and modelled average hourly dispatch profile of large-scale batteries in 2021-22 (MW)



Analysis of existing battery behaviour

Analysing the operational behaviour of existing batteries has informed the evaluation of options available to address imperfect foresight in time-sequential modelling. Figure 28 shows the duration curves for a battery’s state of charge and normalised power dispatched (megawatts dispatched as a proportion of maximum power capacity) of large-scale grid batteries across the NEM over 2022-23. While batteries are generally capable of accessing the full range of their rated power capacity (shown by normalised power dispatch reaching unity), they typically retain some margin of energy (megawatt hours) and remain close to a 30-40% charge state.

Figure 28 Duration curve of large-scale battery normalised power dispatch (left) and state of charge (right), 2022-23

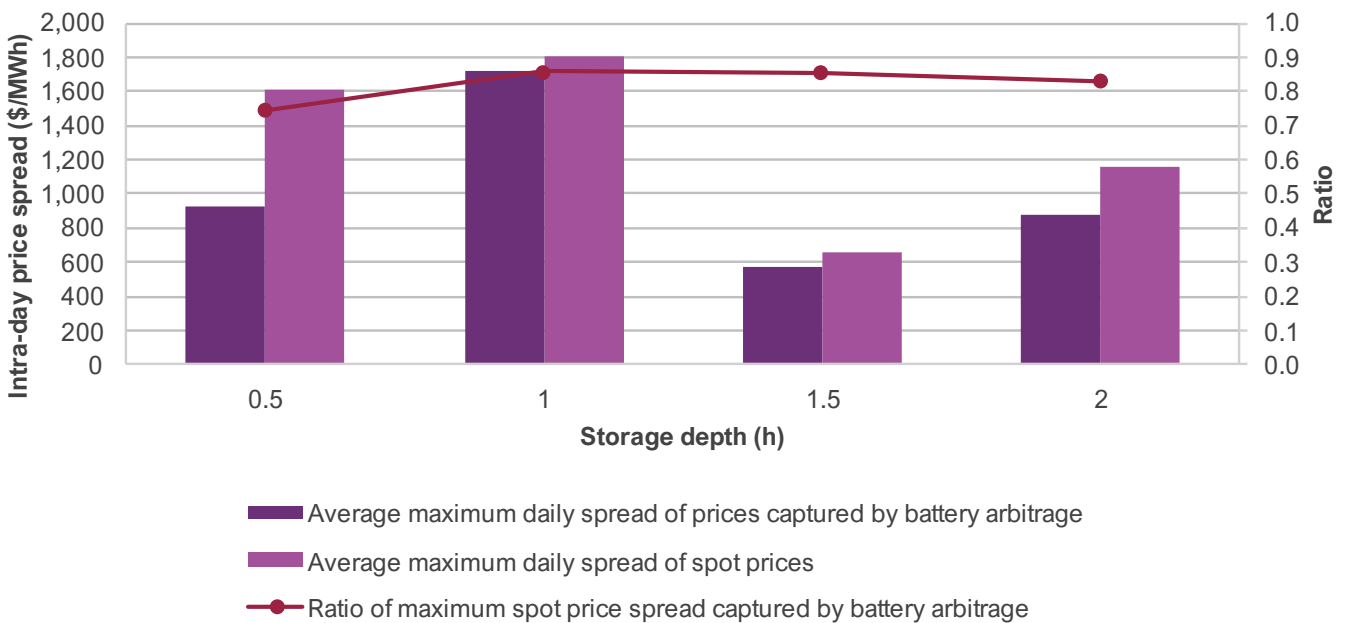


Notes: excludes large-scale grid batteries operated with known contracts that reserve energy capacity or power capacity, and batteries with attached plant loads that do not principally target arbitrage of the wholesale energy market. Normalised power dispatch refers to the dispatched power (megawatts) as a proportion of the battery’s rated power capacity.

This behaviour allows battery operators to manage market uncertainty but will limit their ability to fully discharge during extended high price periods. Co-optimisation between energy and FCAS markets also encourages battery operators to reserve sufficient headroom and footroom capacity to respond to contingency events. In the future, as batteries are increasingly used for energy shifting, reserving power for the provision of FCAS is likely to become less widespread, but retaining some margin for contingencies will remain as a risk management strategy.

Inaccurate forecasts of variability in cloud cover, wind speeds and operational demand mean battery operators often fail to perfectly dispatch into high price intervals. Figure 29 shows the impact of weather forecast inaccuracy affecting the expected operation of VRE, and its impact on battery operation, by comparing the average daily maximum arbitrage opportunity captured by batteries, to the maximum spot price range. During 2022-23, batteries captured between 75% and 85% of the maximum intra-day price spread, with short-duration batteries (0.5 hour) missing substantially more maximum intra-day price spreads compared to longer duration batteries.

Figure 29 Average daily maximum spot price arbitrage potential captured by existing large-scale grid batteries, 2022-23 (MWh)



Evaluation of alternative approaches to modelling imperfect foresight

AEMO's response to the *ISP Methodology* consultation included a commitment to explore alternative approaches to modelling imperfect foresight in the 2024 ISP. To investigate the impact of imperfect foresight on storage operation, AEMO has evaluated three modelling approaches:

- **Derating storage capacity (MWh)** – introduced the storage capacity constraints proposed in the *ISP Methodology* consultation. This is the approach used by the NEM *Electricity Statement of Opportunities* (ESOO)¹³ for reliability assessments.

¹³ See the ESOO and Reliability Forecast Methodology Document, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

- For devices with less than two hours of storage, reduced storage capacity by 50%.
- For devices with two to (less than) four hours of storage, reduced storage capacity by 25%.
- For devices with four to (less than) eight hours of storage, reduced storage capacity by 10%.
- **Capacity reserves** – introduced headroom and footroom reserves that provide sufficient risk mitigation for batteries to capture unexpected system events.
 - The amount of headroom and footroom reserve was equivalent to energy dispatched at maximum power over a five-minute interval, which correlates with the Frequency Operating Standard for the time of frequency restoration (depending on the type of contingency event). This also correlates to observed battery energy management of existing grid-scale batteries.
 - The headroom and footroom reserves 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.
- **Battery unavailability** – introduced randomised battery unavailability events to represent the risk of missing an interval of arbitrage opportunity. The likelihood and severity of an unavailability event was set based on the historical observations shown in Figure 29 above regarding the chance of generating at maximum power during peak periods, and the average power dispatched during peak periods, respectively.
 - For devices with less than one hour of storage, implemented unavailability events 80% of the time, during which only 10% of maximum power is available.
 - For devices with two to (less than) four hours of storage, implemented unavailability events 40% of the time, during which 50% of maximum power is available.
 - For devices with four to (less than) eight hours of storage, implemented unavailability events 20% of the time during which 90% of maximum power is available.

These imperfect foresight tests effectively applied greater relative constraints to shorter duration batteries compared to longer duration storages, as shallower storages are at greater risk of missing a peak price event and losing value due to forecast inaccuracy. Of the over 40 GW of grid-connected storages forecast to be required by 2040 under *Step Change*, over 11 GW is shallow storage, and another approximately 18 GW is orchestrated VPP batteries embedded within the distribution system.

Compared to the perfect foresight case, all foresight tests lowered battery generation, with derating storage capacity and battery unavailability having similarly strong impacts on the total amount of energy dispatched, as opposed to holding headroom and footroom energy reserves. In the latter case, energy reserves may be violated to serve tight market conditions, and under extreme circumstances, allow batteries to access retained energy that may have otherwise been discharged earlier, during periods of lesser energy scarcity.

The applied foresight tests did not reduce battery generation to the low levels observed historically, allowing some margin for future foresight improvement. As more batteries are rolled out it is expected operators will increasingly prioritise energy market arbitrage rather than FCAS revenues.

Figure 30 shows a *Step Change* summer forecast in 2039-40 for Victoria when there is strong reliance on battery operation. In cases where energy limitations have been imposed on batteries by derating, storages are less capable of charging so capture less surplus VRE during daytime hours. Conversely, reserved headroom and footroom energy remain accessible to the battery, if there is sufficient market opportunity or need. Meanwhile, imposing unavailability events cause batteries to miss out on charging during some low-price intervals.

In all cases (top chart), batteries enter evening peak periods with less energy stored, compared to when modelled with perfect foresight, resulting in lower discharges from storage when that capacity is needed. The resultant generation profile under perfect foresight conditions (second chart) is presented alongside the profile when shallow storage has been derated (third chart).

In the perfect foresight case (fourth chart), stored energy can meet most of the post-sunset dispatchable demand, except for during low wind conditions. Under imperfect foresight conditions imposed by battery energy derating, impaired battery operation requires alternative generation to be supplied by other dispatchable generation such as gas, and additional imports from neighbouring regions where available. The degree of foresight therefore impacts short duration storage's ability to shift energy across the day and the magnitude of additional reserves required to maintain reliability.

Figure 30 Forecast impact of battery foresight on summer operability in Victoria, *Step Change, 2039-40* – energy stored in batteries (first chart), generation mix under perfect foresight conditions (second chart), generation mix with battery derating (third chart), and difference in dispatch relative to perfect foresight conditions (bottom chart)

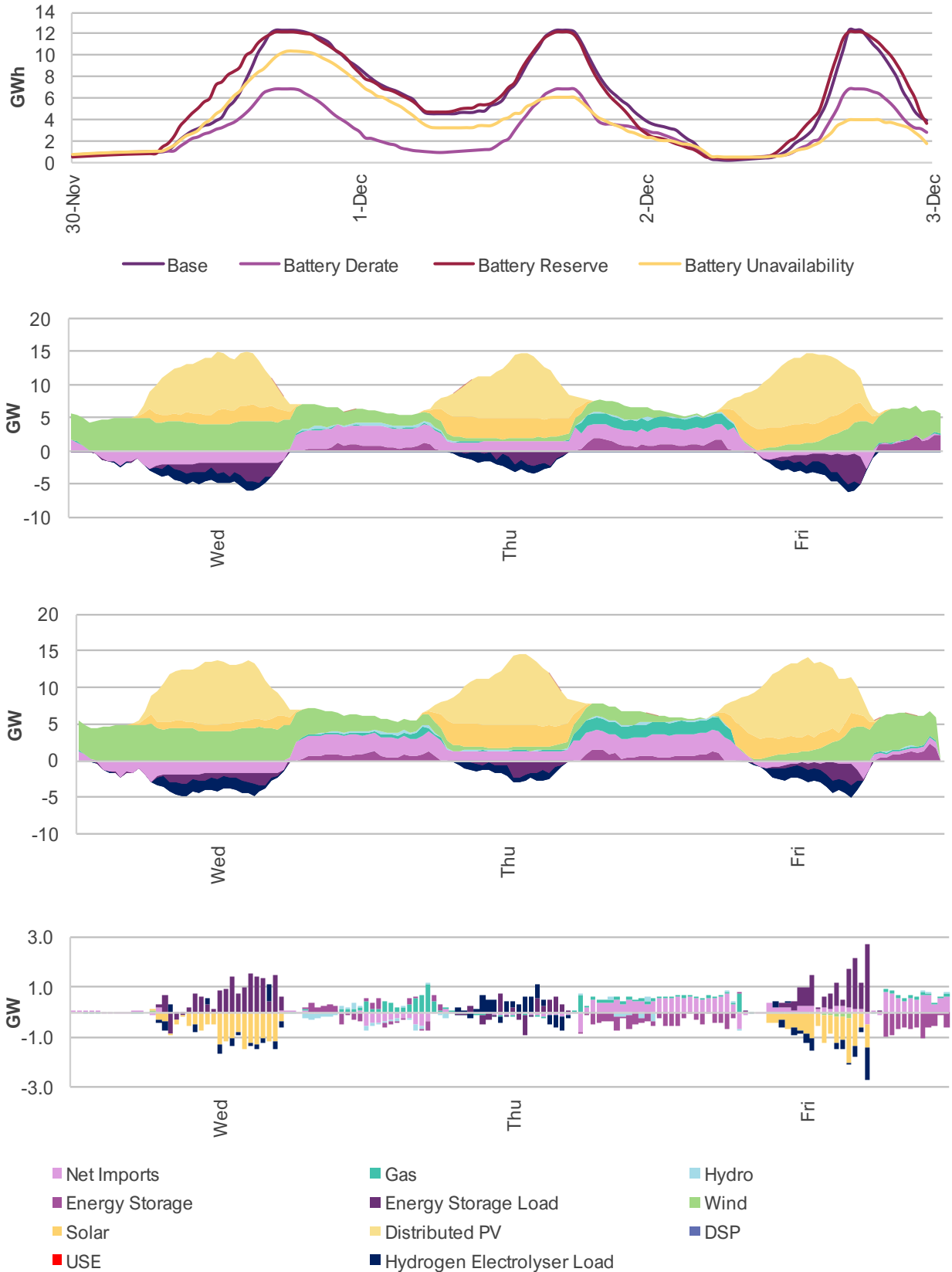
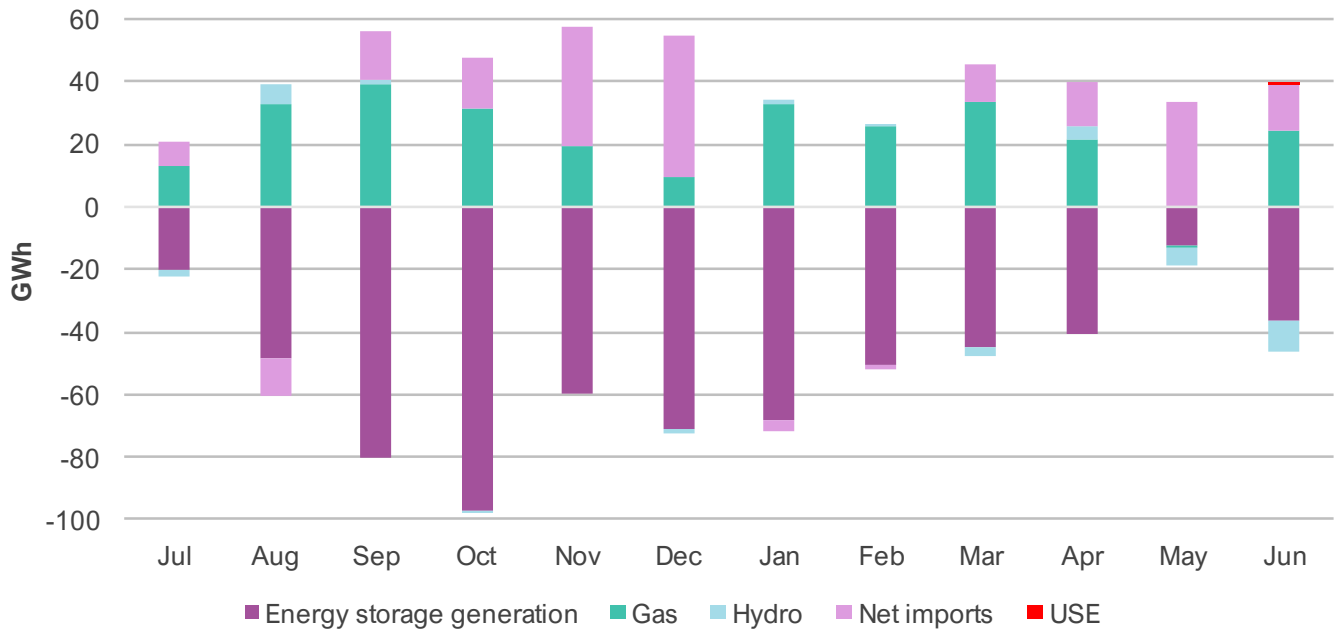


Figure 31 shows that forecast generation from batteries due to modelling with perfect foresight are higher during the spring and summer months in Victoria when batteries cycle to regularly provide intra-day shifting. Modelling outcomes applying battery derating to perfect foresight are overall less impacted during winter months with reduced battery activity due to higher and flatter residual demand profiles.

Figure 31 Forecast difference in monthly generation between perfect foresight conditions and conditions with battery derating in Victoria, Step Change, 2039-40 (GWh)



Note: positive generation in this figure refers to higher dispatch with battery derating, while negative generation refers to higher dispatch with perfect foresight. With battery derating, more gas generation is forecast to be used to compensate for imperfect storage management.

Storage availability may impact system reliability, and require more strategic reserves to mitigate forecast inaccuracy and imperfect foresight risks. During periods of low reserve, having some extra headroom of storage capacity or other reserves would help address more imprecise operation of storages. If storage levels are low going into VRE lulls then reliability risks will increase.

Storage management will become increasingly important and can be improved by better weather forecasting, more timely provision of market information, and increased coordination of energy storages at a system level, including the ability to orchestrate more CER. The availability of other resources such as flexible gas (or hydrogen) generators with appropriate fuel availability will also reduce the impact of imperfect energy management or imperfect weather forecasting on future power system operability.

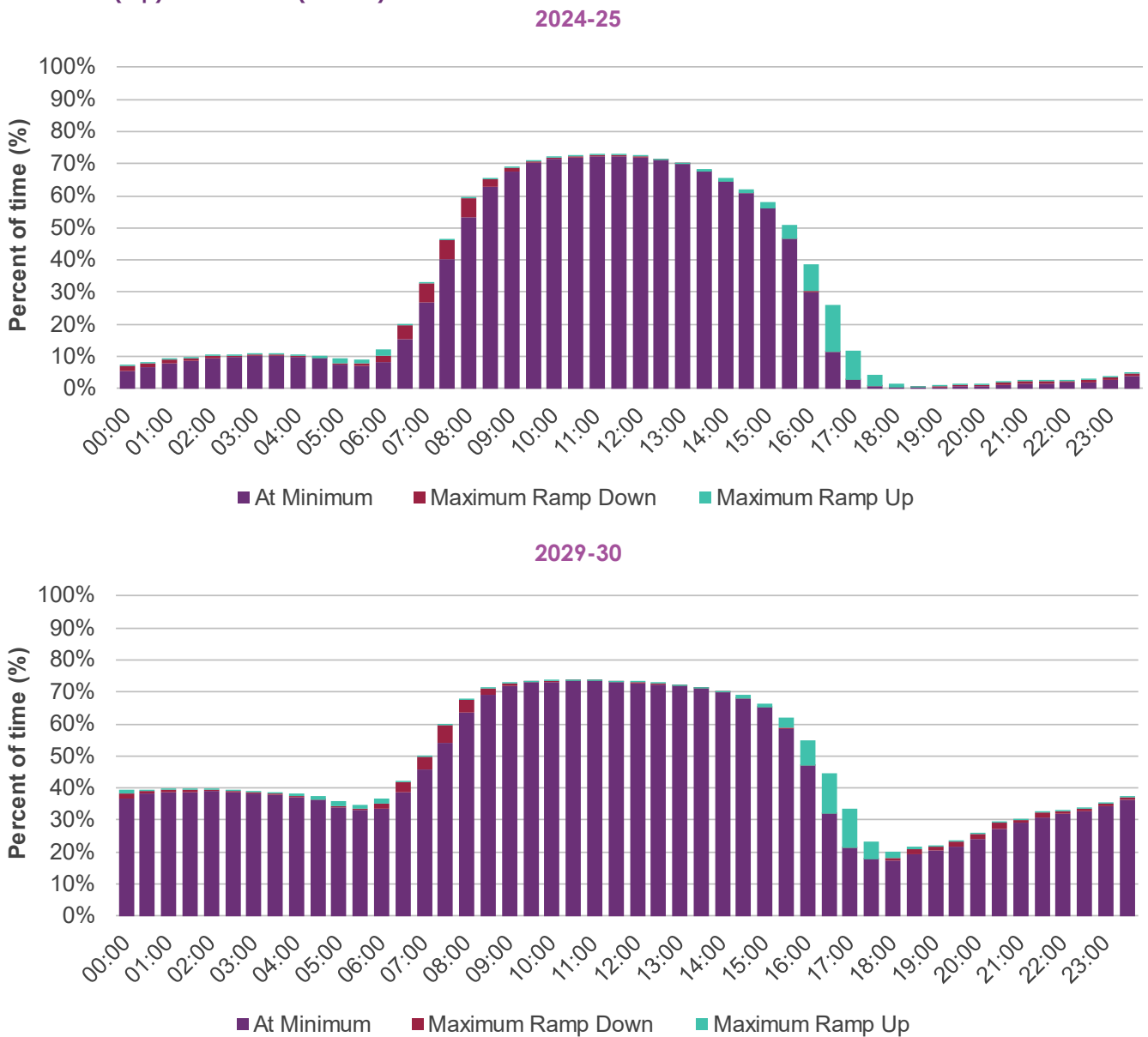


A4.7 Implications for coal operation during the transition

Coal-fired units are forecast to adjust the way they operate with projected increases in VRE penetration. Coal units typically have limited flexibility to ramp output up and down quickly to accommodate supply and demand fluctuations. Coal generators in the future are more likely to operate for longer periods at minimum stable levels with high penetration of VRE. This may lead to some operators mothballing or seasonally withdrawing coal capacity during sustained periods of high VRE availability, particularly in spring when energy availability is high, and demand is low leading to more frequent low-priced periods.

Figure 32 shows the percentage of time in each hourly period that black coal generators in New South Wales and Queensland are forecast to operate at minimum generation levels in 2024-25, and also in 2029-30.

Figure 32 Forecast black coal percentage of time at maximum ramp and minimum load, Step Change, 2024-25 (top) and 2029-30 (bottom)





These generators are forecast to ramp down when the sun rises, with utility-scale solar expected to be dispatched ahead of coal capacity that is offered above their minimum operating levels (subject to the bidding behaviour of the generation fleet). They are then anticipated to operate at minimum generation levels during the day before ramping up to meet evening peak demand. The projected increase in the penetration of wind generation to 2029-30 is expected to impact coal generators, causing more frequent operation at minimum generation levels, in both the day and the night.

Seasonal operation may improve the economics of operating some coal-fired power plants. Operating a generator at a spot-market loss position may be avoided if operators consider temporarily withdrawing the unit will result in a lower re-start cost than operating during VRE surpluses. Coal generators with higher operating costs may benefit from withdrawing their units to avoid operating losses if sufficient alternative generation were available to maintain an appropriate reliability position, and to cover retail or contract positions. Ultimately, the way in which generation portfolios are operated will depend significantly on the circumstances of the portfolio, the level of contracting that each portfolio has (for fuel supplies, and for generation output), and the technical capability of individual plant to flex up or down to take advantage of spot pricing opportunities.



A4.8 Impacts of gas system adequacy on system operability

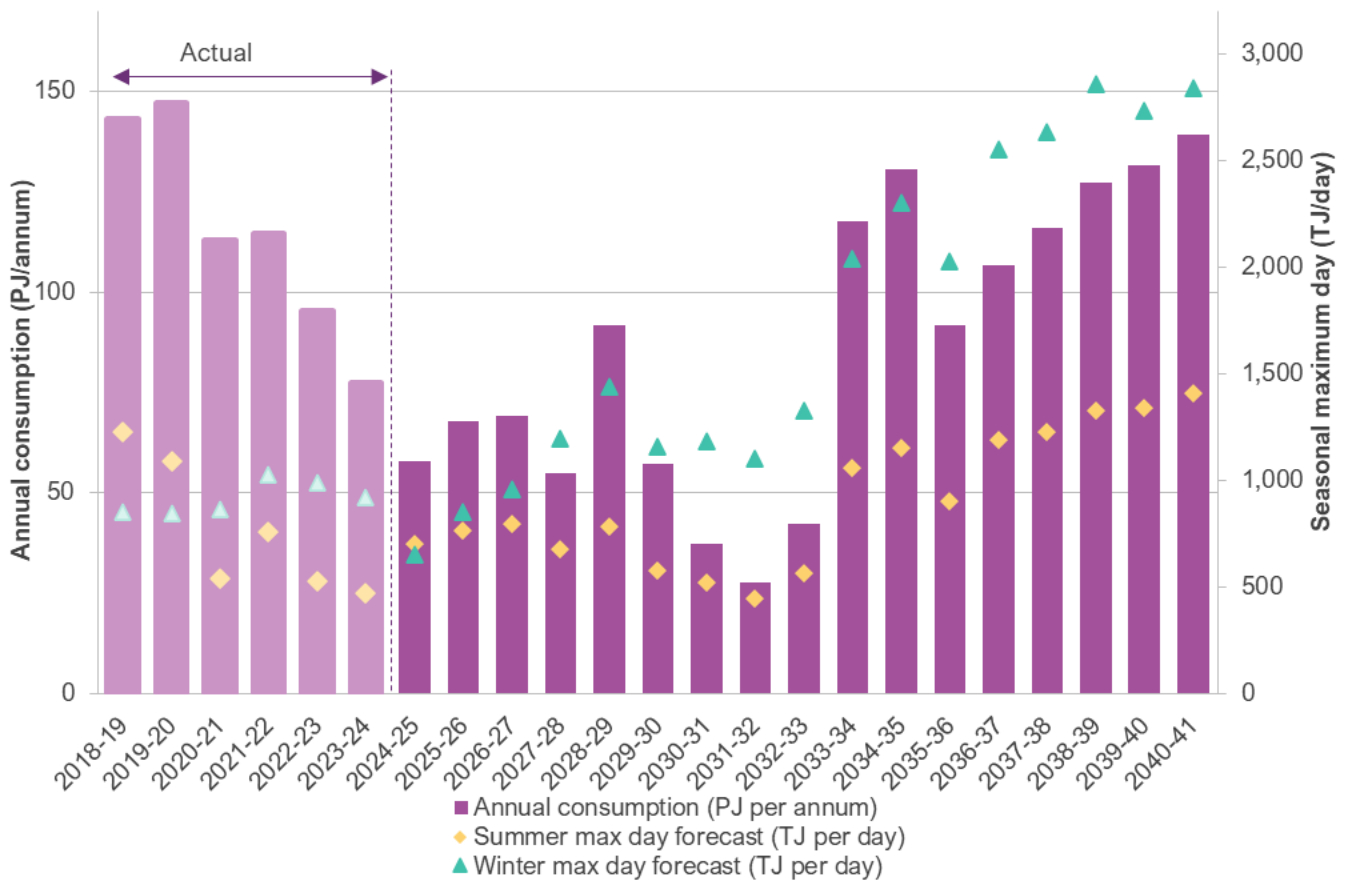
Transition of GPG from mid-merit to flexible generation

GPG is expected to continue to play an important role in the NEM by helping manage longer periods of low VRE generation and providing firming when other dispatchable sources are unavailable. GPG’s role also extends to providing critical power system services.

GPG is forecast to be used less frequently during daily peak demand periods but will be critical to maintaining reliability during less frequent periods of more widespread low VRE output and during longer dark and still events (see Section A4.5). This is expected to be more likely during winter periods as electrified heating loads increase energy consumption during that season.

Figure 33 shows forecast annual consumption of gas for electricity generation returning to recent historical levels during the mid-2030s, due to the combined effect of coal retirements, electricity consumption growth, and the need to firm high levels of VRE. Daily maximum demand for gas is forecast to increase significantly during winter as a result of electrification of heating loads and longer periods of lower VRE production.

Figure 33 Actual and forecast NEM GPG annual consumption (PJ/y) and seasonal maximum daily demand (TJ/day) in Step Change, 2018-19 to 2040-41



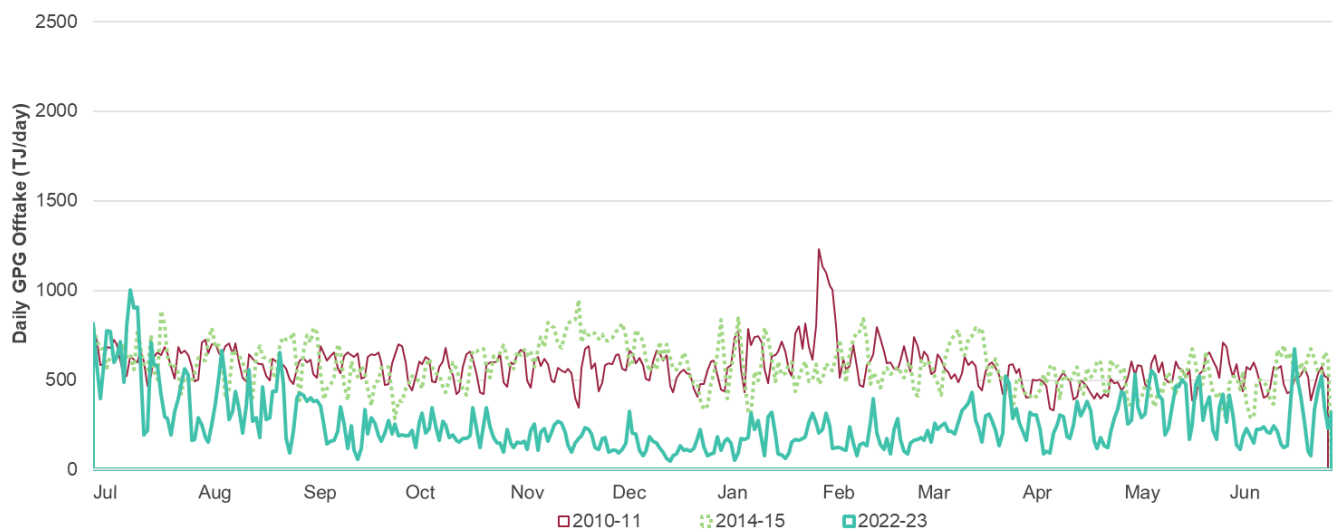
Note: Actual data for 2023-24 is estimated as of 17/6/2024.



Mid-merit generators (primarily combined cycle gas turbine (CCGT) technology) are expected to be gradually replaced by new flexible generators (primarily open cycle gas turbine (OCGT) technology)¹⁴. OCGT technology is less fuel efficient, but has lower up-front capital costs and can operate more flexibly, so it is a more appropriate replacement technology both technically and economically when operating at lower annual utilisation factors.

Figure 34 shows the profile of gas offtake in terajoules per day (TJ/d) for power generation throughout the year in 2010-11, 2014-15 and 2022-23. Historically, higher GPG usage occurred throughout the year, with marginally higher consumption during November to March and some high summer daily peaks. By 2022-23, with greater penetration of VRE, the utilisation of gas has generally declined, with some increases in offtake during winter operations when VRE generation is typically lower.

Figure 34 Historical daily NEM GPG offtake in 2011-12, 2014-15 and 2022-23, Step Change, (TJ/d)



In contrast to the flatter generation profiles during 2010-11 and 2014-15, Figure 35 shows the increasing role flexible gas is forecast to play in supporting winter peak electricity demand from 2024-25 to 2044-45, with GPG generally increasing during winter (during non-peak demand events) when VRE generation is relatively low.

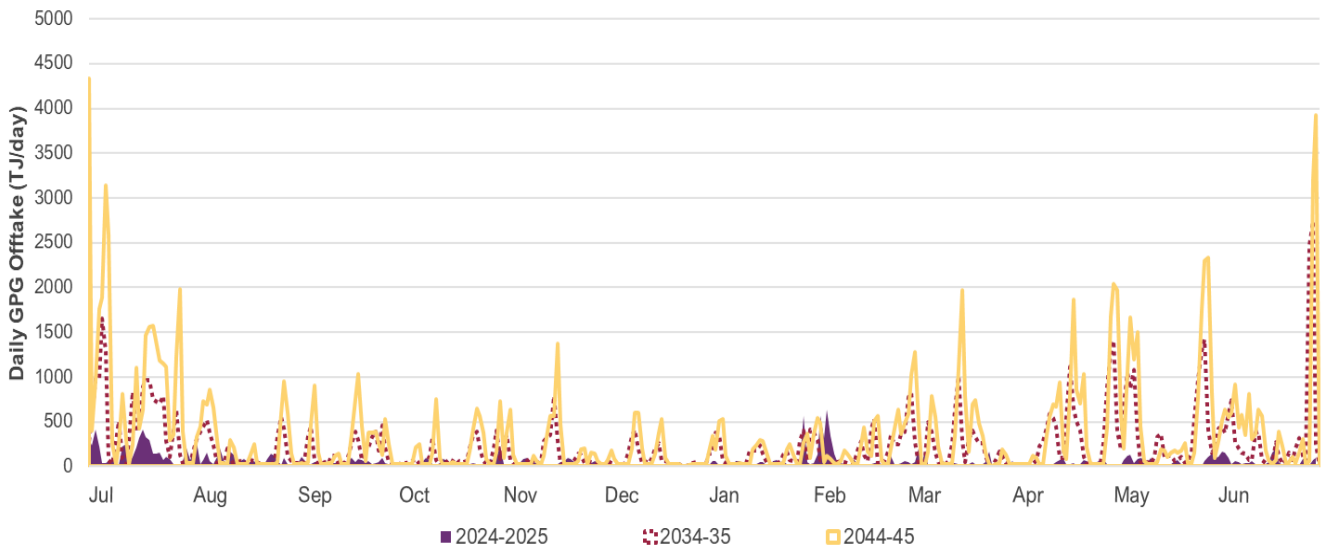
This continuation of the trend observed in recent years to operate GPGs more intensively in winter will increase demands on the east coast gas system to deliver higher volumes of gas over shorter periods of time.

To accommodate this increasing role, AEMO anticipates that greater fuel security through on-site liquid fuel storages may be appropriate depending on the gas infrastructure investments that are made over the coming years. On-site storages for liquid fuels provide fuel security and enhance power system reliability during low VRE periods when there is high underlying demand.

¹⁴ In some cases, existing CCGT power stations such as the Tamar Valley power station in Tasmania may switch back to being taken out of service for extended periods, but generation capability is maintained if needed for power system reliability and security.



Figure 35 Forecast daily NEM-wide GPG fuel offtake in 2024-25, 2034-35 and 2044-45, reference year 2011, Step Change, (TJ)



Gas production and pipeline capacity limitations may constrain gas supply for GPG during peak periods

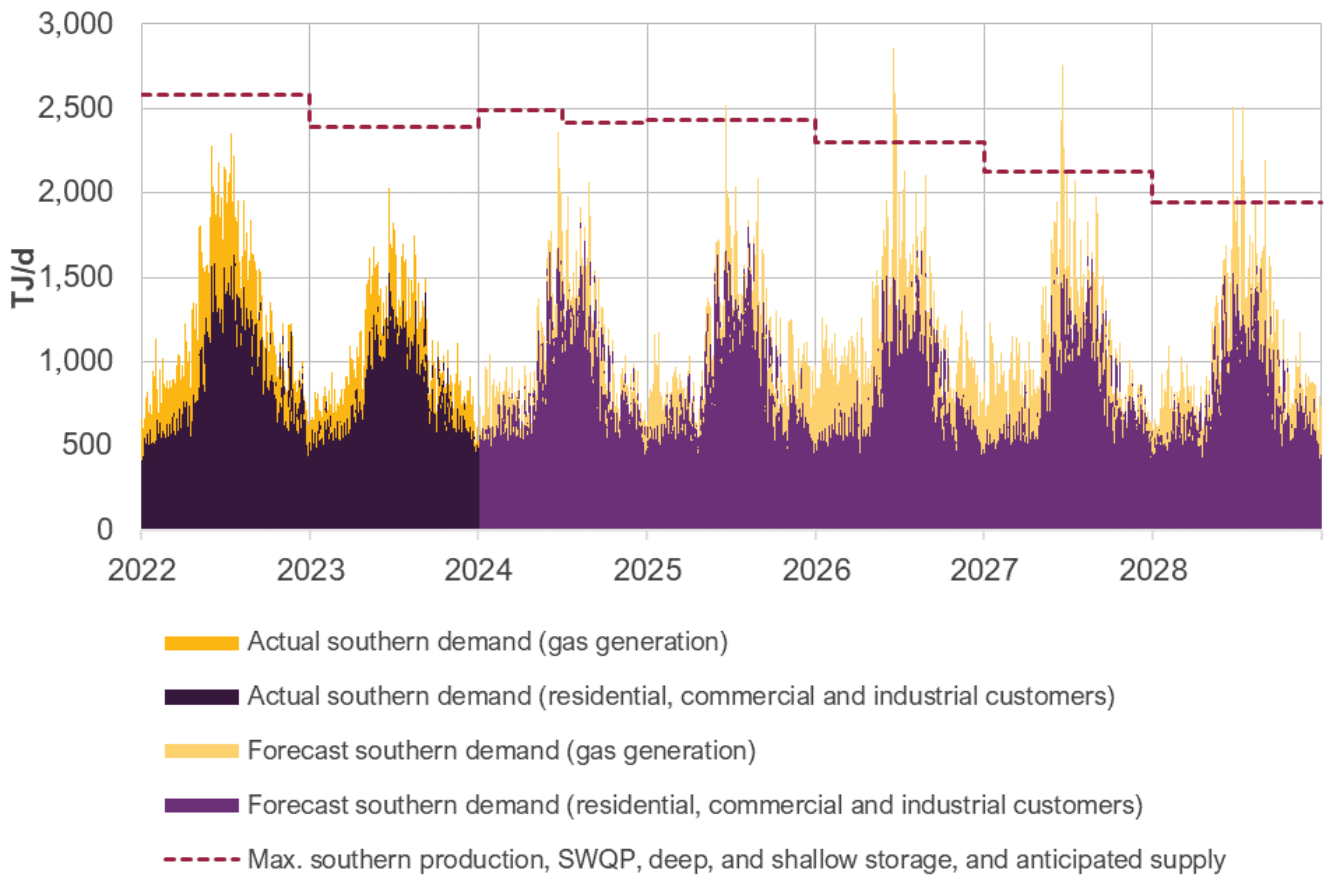
The 2024 *Gas Statement of Opportunities* (GSOO) considers the availability of existing, committed and anticipated gas supplies and mid-stream gas infrastructure to meet gas consumers' needs as well as gas generators' needs. The 2024 GSOO identified that during peak days, forecast production and pipeline infrastructure may be unable to supply southern demand for GPG and for residential, commercial and industrial customers.

Figure 36 shows the maximum gas supply (dotted red line) that can be provided to southern customers and GPGs based on existing, committed and anticipated gas supply and infrastructure.

In the longer term, from 2028, the GSOO forecasts structural supply gaps emerging, requiring new gas supplies to be developed. The 2024 ISP assumes this new supply is developed to service gas customer and GPG demand in the NEM. Even with new supply to effectively replace current sources, mid-stream gas infrastructure is forecast to become progressively more constrained at peak times from the early 2030s when flexible gas generators are forecast to operate at maximum capacity for relatively short periods when VER availability is low.



Figure 36 Actual daily southern gas system adequacy since January 2022, and forecast to 2028 using existing, committed and anticipated supply projects (TJ/d)



On-site storage of secondary fuels will be important for new GPG to provide a resilient firming solution

For this 2024 ISP, AEMO has added gas supply limits to the southern regions (New South Wales, Victoria, South Australia and Tasmania) based on the current production and delivery limitations of the east coast gas system. To ensure GPGs are resilient to conditions that constrain gas availability from the pipeline network, AEMO has included a requirement for all new entrant flexible gas generators to incorporate additional on-site storage¹⁵. Utilisation of this stored secondary fuel is then priced at a premium value, reflective of AEMO’s liquid fuel price forecasts.

Further information about the implementation of gas delivery constraints and on-site liquid storages for gas generators can be found in Section A2.2 of Appendix 2.

The use of secondary fuels can enable continued operation of GPG during periods of pipeline delivery risks, most likely when there is coincident high gas demand periods from gas consumers and gas generators. These represent prudent investments to reduce the risk of electricity demand curtailment and improve system reliability. Future gas location decisions will need to consider expected availability of gas infrastructure (including pipelines

¹⁵ GHD Advisory. 2022. *Power station and associated costs*, page 17, at <https://www.erawa.com.au/cproot/23060/2/-BRCP.2023---Power-Station-and-Associated-Costs-Report---GHD-Advisory---Dec-2022.PDF>.



and gas storages), future gas supplies, and secondary fuels, along with proximity to transmission infrastructure and electrical loads.

Operating GPGs when the gas system is constrained using secondary fuels

The 2024 GSOO identifies options that may be available to address yearly supply gaps and gas supply shortfalls¹⁶. Various options are currently under consideration by gas market participants including expanded pipeline transportation developments, liquefied natural gas (LNG) import terminals, new domestic gas production facilities (including renewable gases), and gas storages.

In this analysis for GPG operations, AEMO assumed new gas supplies will be developed but did not assume further pipeline or storage infrastructure augmentations. A seasonal gas supply limit of 1,500-1,800 TJ/d has been applied for southern GPGs to reflect existing gas system delivery constraints. This is based on the historical maximum southern gas supply capacity in 2023-24 (Figure 36) and projections for non-GPG gas demand southern states in 2044-45.

Figure 37 displays the forecast daily gas and diesel consumption for operation of GPG in the southern regions of the NEM in 2044-45 (reflective of conditions observed historically in 2010-11). It shows peak GPG demand during winter still cannot be met even with new gas supplies in the south, and some GPG must switch to on-site diesel storage to continue their operations.

Figure 37 Forecast daily gas and secondary fuel (diesel) consumption from GPG in southern NEM, Step Change, reference year 2011, 2044-45 (TJ/d)

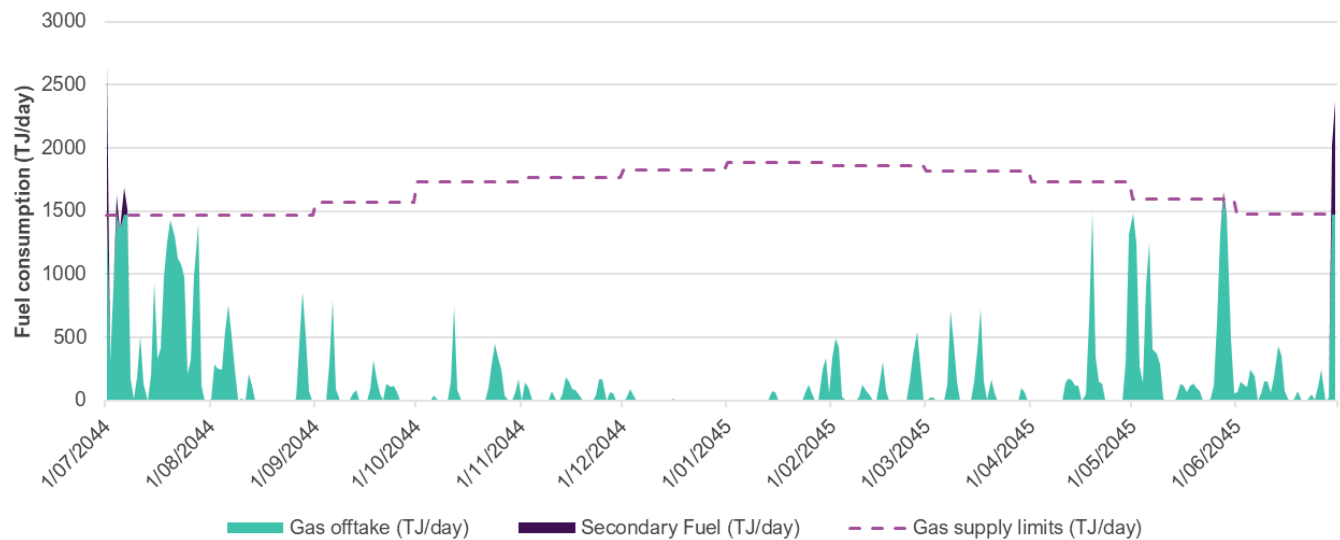


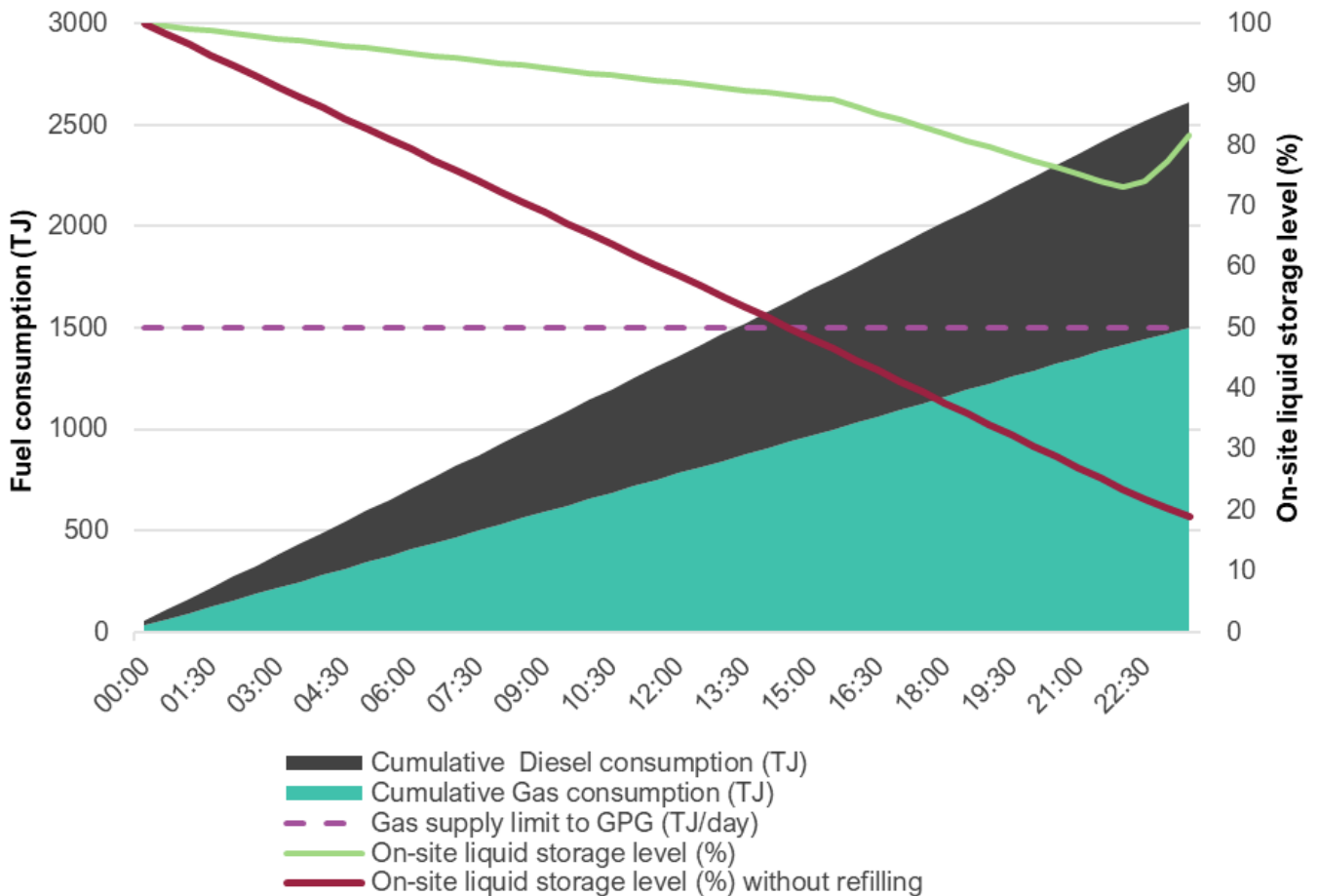
Figure 38 presents a closer examination on the operation of the southern GPG fleet and the aggregated percentage of diesel in GPG liquid fuel storages during an extreme VRE drought day in July 2044-45 (see Section A4.5 for more information about this event). Each new entrant GPG was assumed to have a 14-hour on-site

¹⁶ See the 2024 GSOO Section 5 'Options to address forecast supply challenges', at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf?la=en.



storage. It shows 1,100 TJ (or almost 30,000 litres¹⁷) of diesel is projected to be required for southern GPGs and the reserve level of this diesel storage may drop to as low as 20% if no refilling is available. This demonstrates that new GPGs (especially those located in southern states) are forecast to require at least 14 hours of on-site storage of secondary fuels for continuous and reliable operation.

Figure 38 Cumulative forecast gas and diesel consumption (TJ) of southern NEM GPGs and their on-site liquid storage level on an extreme VRE drought day in 2044-45



A portfolio of solutions including mid-stream gas infrastructure, on-site secondary fuel storages, and alternative electricity storages will likely be required in the future to ensure the most cost-effective and reliable operation of the NEM.

¹⁷ Based on average heat content of 38,290 kilojoules (kJ)/litres from diesel.

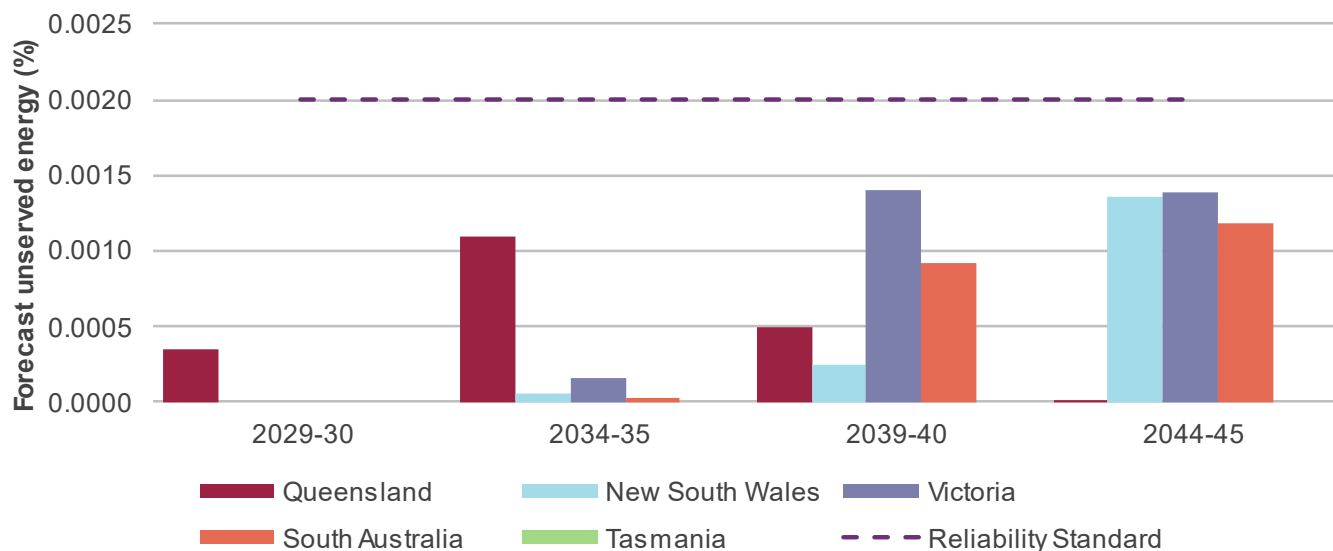


A4.9 Maintaining reliability during the transition

AEMO has forecast reliability outcomes for the 2024 ISP’s ODP using an approach consistent with the reliability assessments conducted for the NEM 2023 ESOO¹⁸, accounting for weather variability and generator outages¹⁹.

The reliability standard is a measure of expected USE in each region, requiring that no more than 0.002% of energy demanded in any financial year. With the 2024 ISP’s generation, storage and transmission developments, expected USE is forecast to be within the reliability standard in all regions over the medium and longer term, as shown in Figure 39.

Figure 39 Forecast reliability outcomes by region, Step Change, 2029-30 to 2044-45



Reliability risk shifts from summer to winter

The 2023 ESOO and 2023 ESOO Update forecast the highest risk of expected USE during the next 10 years to be during hot evenings in summer, when demand for cooling increases operational demand and solar generation drops. Reliability risks are most likely to arise if large generation units experience outages, or coincident low wind generation occurs across NEM regions.

In the longer term, with the forecast increase in electrification of heating loads in winter, reliability risks are forecast to shift seasons from summer to winter in all mainland regions. During winter, high demand for electrified heating loads is forecast to coincide with reduced solar output, particularly in the south where days are shorter. When wind output is also low, the imbalance between VRE production and high demand creates a tight supply-demand balance, increasing reliability risks.

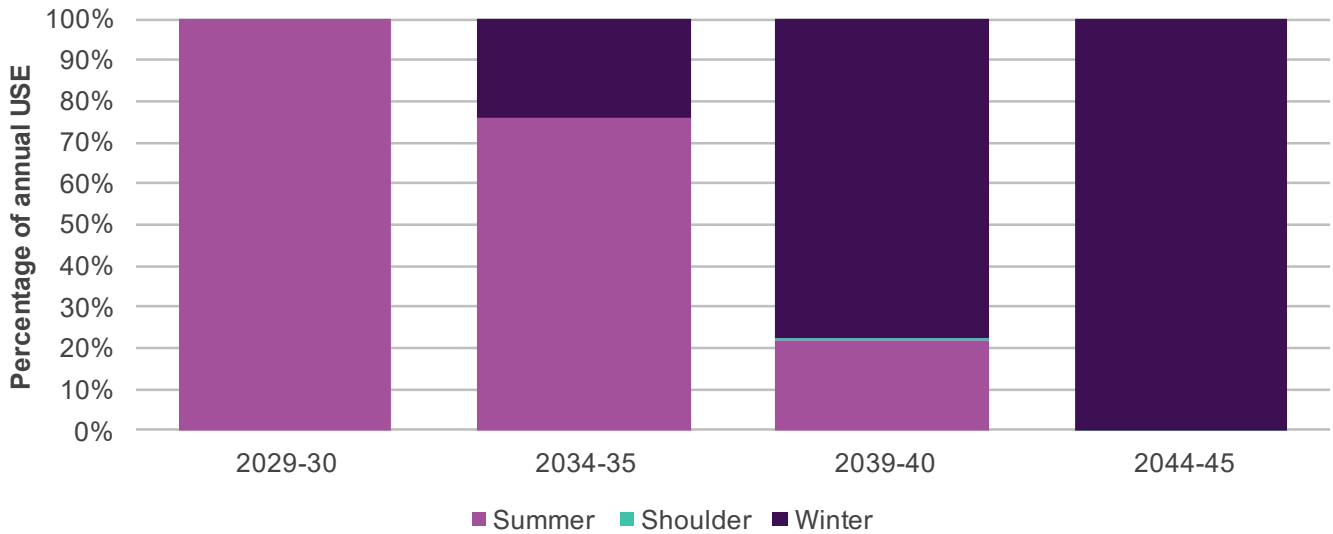
Figure 40 shows the seasonal share of reliability risks, as indicated by the volume of expected USE, across a range of forecast conditions between 2029-30 and 2044-45.

¹⁸ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

¹⁹ To manage simulation complexity, this reliability analysis has simulated fewer random generator outage patterns than is applied to do a formal reliability assessment in the ESOO.



Figure 40 Seasonal share of expected USE, Step Change, 2029-30 to 2044-45



These forecast reliability outcomes are driven by the frequency and severity of weather events leading to low VRE output and higher demand. Table 1 summarises the differences between summer and winter reliability events.

Table 1 Comparison of forecast summer and winter reliability risks

	Summer events	Winter events
Reliability challenge	Adequate available generation capacity for the hottest days.	Energy adequacy throughout winter, particularly for southern regions with relatively high heating loads.
Key weather driver	High temperatures create high cooling loads.	Cool temperatures create high heating loads. Exceptionally widespread calm weather pattern over south-east Australia. Low wind availability over a period of one to five days.
Factors affecting reliability	Concurrent low wind, unavailable generation capacity, transmission outages.	Concurrent cloud cover limiting solar energy, shorter days, cold conditions driving up heating load, firm generation outages, transmission outages.
Time of day (intra-day) reliability challenges	During early evening as solar output reduces to zero, but load remains high. Generation fleet flexibility to accommodate extreme ramping is important.	Beginning during the night and into the early morning as shallow and medium storages run empty.
Limiting (bounding) factors	The gap between the maximum instantaneous demand and maximum available generation supply.	Duration of low VRE event and geographical area impacted.
Key supply-side risk	Capacity unavailable at peak due to generation or transmission outage.	Energy unavailable over wind drought period due to lack of access to energy reserves (deep storage or GPG).

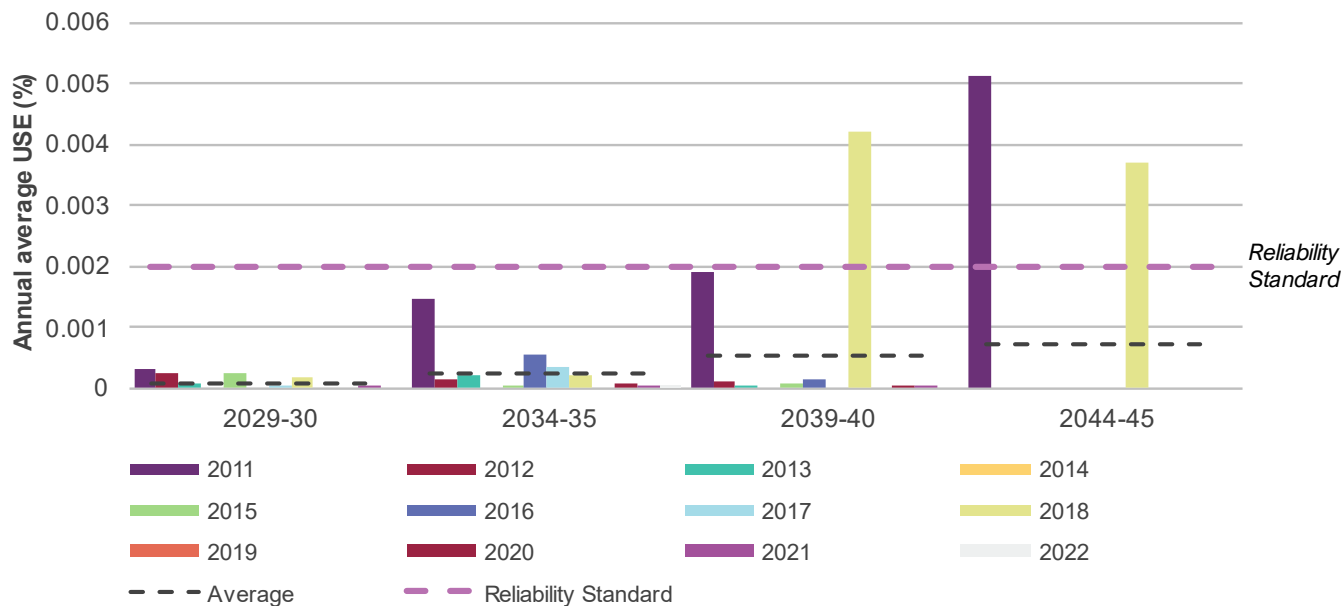
Reliability risks in the NEM vary with differing weather conditions and over time as more existing capacity retires from the power system. Figure 41 shows the forecast expected USE outcomes averaged across the whole NEM between 2029-30 and 2044-45. This figure highlights the impact of variable weather conditions, with similar near-term risks (before 2039-40) forecast across a range of weather conditions, reflecting lower reliance on VRE



to meet peak demands given greater ongoing availability of coal generators. The dotted line shows the average forecast USE across all simulated weather reference years.

In the long term, larger quantities of expected USE are forecast, but only in two of the 12 reference years, indicating a higher impact but lower probability of reliability risks. This shows that the ODP is resilient to a broad range of weather conditions, but may be severely impacted during lower probability events, depending on the availability of firming and backup resources in the NEM.

Figure 41 Average NEM-wide unserved energy by reference year, Step Change, 2029-30 to 2044-45



In Appendix 2, Section A2.5.7 investigates a sensitivity around the generation mix required in the NEM if all weather in future years is similar to that seen in the 2011 reference year.

Forecasting future weather conditions is a key uncertainty, and highly influential on the future reliability of the NEM. Weather conditions directly influence not only the magnitude of weather-induced demand peaks, but also the duration and frequency of extreme wind and solar drought conditions. See Section A4.5 for additional ‘what if’ analysis regarding the operation of the ODP under longer duration renewable energy droughts than have been observed historically. This highlights the important role energy storages and flexible gas play in maintaining energy adequacy and reliability.



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 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	-	<p>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.</p> <p>Anticipated projects are included in all ISP scenarios.</p>
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, 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	DSP	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.
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.
Distributed solar/ distributed PV	-	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.
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.
Net market benefits	-	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.
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 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 power 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 high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.
Renewable drought	-	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.
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 the 2024 ISP, AEMO has considered three scenarios: <i>Progressive Change</i> , <i>Step Change</i> and <i>Green Energy Exports</i> .



Term	Acronym	Explanation
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 modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating 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 CER, including batteries and electric vehicles.
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.