2020 ISP Appendix 6. Future power system operability

July 2020

Important notice

PURPOSE

This is Appendix 6 to the Final 2020 Integrated System Plan (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes this 2020 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 broader functions under the National Electricity Rules to maintain and improve power system security. In addition, AEMO has had regard to the National Electricity Amendment (Integrated System Planning) Rule 2020 which commenced on 1 July 2020 during the development of the 2020 ISP.

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Summary

This Future Power System Operability appendix provides estimates of the reliability and operability of the development paths identified in this ISP. It studies VRE penetration, coal ramping and flexibility, storage dispatch behaviour, and GPG operation.

This appendix also provides further detail on a regional basis, delving into key insights and/or risks that specifically impact each region.

A6.1. Introduction

This appendix takes the next step from Appendix 2 and Appendix 4, which provide an annual outlook of generation capacity builds and retirements, costs and generation. Appendix 6 looks in more granular detail at how the NEM is forecast to be operated on a 30-minute basis, taking into account (among other things) the detailed technical limitations of each unit in the generation fleet, thermal and stability constraints on the transmission networks, and detailed fluctuations in weather and customer demand. In short, this appendix provides cross-checks to answer the question of whether the key development paths identified by this ISP can be operated successfully, and project where some of the future challenges and risks may lie. Further information on the requirements for power system security are provided in Appendix 7.

This appendix is set out in the following sections:

- **Power system operability models and inputs (A6.2):**
  - This section provides an overview of the suite of time-sequential models used to assess reliability and operability of the NEM for this ISP. This section also provides some insight into the series of historical reference year weather patterns used for these models.
- **NEM-wide operability outlook (A6.3):**
  - This section starts with a reliability outlook to provide indicative assessments as to whether the development paths studied in this ISP lead to reliable NEM outcomes according to the Interim Reliability Measure (IRM), or equivalent, or the current reliability standard. This section then provides an overview of the NEM-wide operability implications that the NEM will need to adapt to, given the changing generation and interconnection forecast in the NEM. Areas of analysis include:
    - VRE penetration.
    - Coal ramping and flexibility.
    - Storage dispatch behaviour.
    - GPG operation.
- **Regional risks and insights (A6.4):**
  - This section provides more detail on a regional basis, delving into key insights and/or risks that specifically impact each region.

A6.2. Power system operability models and input

This ISP investigates in detail how the NEM may operate on a period-by-period basis into the future, based on some of the candidate development paths considered.

A6.2.1 ISP operability models

The market modelling studies used to develop this ISP apply a suite of short-term time sequential models. More details can be found in AEMO's Market Modelling Methodologies[1], but in summary, the time sequential model uses the generation and transmission development path as identified by this ISP. It is a time-sequential chronological model that determines dispatch, on a half-hourly basis, while ensuring that various power system limitations (such as generator availability, network constraints, and forced outages) are met. This type of model renders a realistic supply/demand assessment in terms of capturing real-time market dynamics on a half-hourly basis.

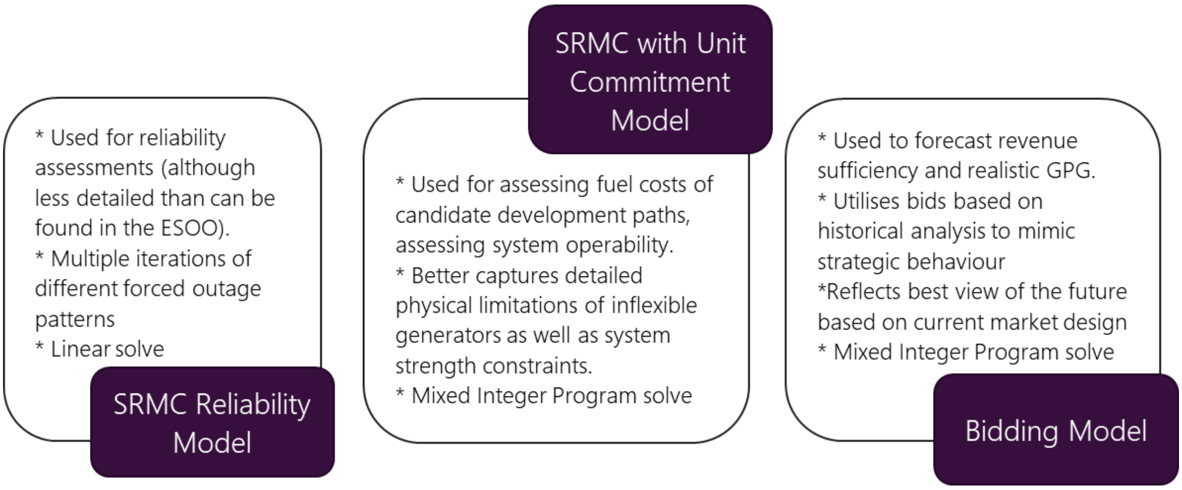
The ISP forecasting suite of short-term time sequential modelling comprises three models:

- The Short Run Marginal Cost (SRMC) Reliability model;
- The SRMC with unit commitment model; and
- The Bidding model.

Figure 1 summarises the three different short-term models used for the ISP described in further detail below.

[1] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

Figure 1 ISP time sequential modelling suite



All three models are implemented with 24 hours of perfect foresight, with an additional forward-looking period with a less granular resolution modelled to inform dispatch decisions towards the end of each step. This ensures that dispatchable generation – particularly storage – can be optimally operated to ensure that energy is available during the most valuable periods.

SRMC Reliability model

The SRMC model is a time-sequential model used to conduct half-hourly simulations to validate the generation and transmission build when operational conditions and network limitations are modelled, to identify possible reliability standard exceedance. As mentioned, this reliability model is implemented with foresight. If storage is not optimised perfectly with coordination across the fleet, then actual reliability outcomes may be slightly worse than forecast.

The reliability assessments derived from this model are less detailed than standard ESOO reliability modelling; the results should only be considered as indicative and not be considered a complete reliability assessment.

SRMC with unit commitment

The SRMC model with unit commitment leverages SRMC dispatch assumptions along with unit commitment decisions, technical plant limitations (including but not limited to minimum up and minimum down times), ramp rates, and system strength requirements. This model is based on a mixed integer program and employs complex heat rate assumptions. Dispatch analysis used to inform assessment of key operability requirements such as inertia and system strength discussed in Appendix 7 has been completed using this model.

Bidding model

The bidding model is an alternate model that has been used to forecast unit dispatch behaviour, calibrated using real historical unit and portfolio bid behaviour. For the ISP, this model has been used to inform revenue sufficiency analysis and GPG forecasts. This model utilises the technical plant limitations similar to the SRMC with unit commitment model, also implementing a mixed integer program. It is computationally intensive to simulate, and therefore is only used for select purposes where the other two models would not suffice.

A6.2.2 Reference years and weather patterns

The availability and variability of renewable energy, including hydro generation, is important given the degree of penetration of intermittent and weather-driven generation projected. The ISP attempts to capture a wide range of possible weather outcomes that could impact NEM capacity expansion and operation.

To capture short- and medium-term weather diversity, AEMO optimises expansion decisions across multiple historical weather years known as 'reference years'. Where practical, these weather years also capture the variance around a long-term climate trend. Historical weather patterns from 2010-11 to 2018-19 were used to create corresponding demand, wind, solar, and hydro inflow traces.

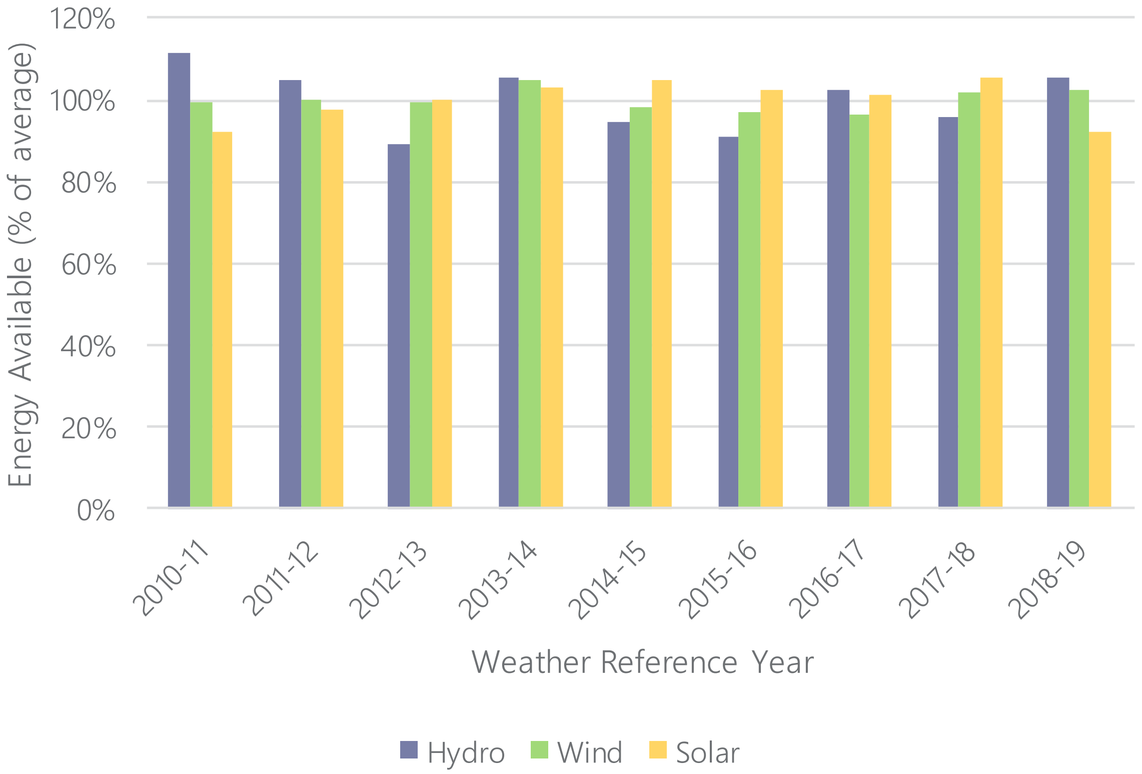
The use of multiple reference years allows the modelling to capture a broad range of weather patterns which can simultaneously influence customer demand, wind, solar and hydro generation outputs. This approach increases the robustness of AEMO's expansion plans by inherently considering the risks of renewable energy "droughts", representing extended periods of very low output from any particular renewable generation source, which are observed across the NEM.

Figure 2 shows the relative abundance of hydro, solar and wind energy across the nine weather reference years. As more variable renewable energy (VRE) capacity is built in the NEM, as forecast in this ISP, the NEM's reliance on weather as a source of energy also increases. Reference year modelling ensures this uncertainty is accounted for.

Each time sequential model in this ISP has utilised a different range of reference years to capture the appropriate mix of weather conditions suitable for the model's purpose:

- The SRMC Reliability model considers all reference years between 2010-11 and 2018-19, to understand the complete reliability risk under the full range of recent historical weather outcomes.
- The SRMC with unit commitment model looks at 2012-13, 2014-15, 2016-17, and 2018-19. Due to the time this model takes to run, a subset of reference years were chosen, with these reference years selected because they provide good coverage across combinations of high/low/average wind/solar/hydro availability, sufficient to study the range of operability outcomes.
- The Bidding model is used to understand system-normal behaviour and average trends, and as such uses only the 2012-13 reference year for wind and solar availability, as this produces reasonably average outcomes for those technologies. Hydro inflows are averaged across all reference years, as the 2012-13 reference year would produce dry-year outcomes.

Figure 2 Abundance of hydro, solar and wind energy across reference years compared to nine-year average



A6.3. NEM-wide operability outlook

The ISP outlines a development path that is quite different from the system operating today. In this ISP, AEMO has assessed requirements for reliability, security, and operability of the power system.

A6.3.1 Estimated reliability of the NEM

Key messages

- Under Central scenario projections, incorporating the least-cost development path, all NEM regions are indicatively projected to meet the reliability standard and the IRM (and equivalent after 2025), with these exceptions:
  - The retirements of the Liddell and Osborne power stations in New South Wales and South Australia respectively in 2023-24 may to lead to reliability levels in excess of the IRM equivalent in both regions, with these reliability risks reducing after the commissioning of Project EnergyConnect the following year.
  - Following the retirement of Yallourn Power Station in 2032-33, Victoria is forecast to maintain reliability estimates within the IRM equivalent provided the Victorian SIPS battery is developed[2]. Without this investment, the IRM equivalent may be breached.
- Risks and uncertainties remain that may test the reliability and resilience of the NEM under the least-cost development path, highlighting the importance of further interconnection within the NEM. These risks include weather events, prolonged generator or transmission outages, and major market events such as early retirement of coal generation.

The NEM reliability framework aims to deliver adequate power and demand response to ensure the reliability standard is met. The reliability standard requires that expected unserved energy (USE) in a region is 0.002% or less of the total energy needs in that region for a given financial year.

The Interim Reliability Measure (IRM), agreed to at the March 2020 COAG Energy Council seeks to ensure expected USE is no more than 0.0006% in any region in any financial year. It is intended to supplement the existing reliability standard for a limited period of time by allowing the Retailer Reliability Obligation (RRO) to be triggered by a forecast exceedance of the IRM, and allowing AEMO to procure reserves if the Electricity Statement of Opportunities (ESOO) reports that this measure is expected to be exceeded. This change has been made through the Draft National Electricity Amendment Rule 2020, clause 3.9.3C.

While the IRM is only intended to cover the period to 2025, AEMO has also assessed reliability against this measure throughout the modelling horizon on the assumption that any future measure that replaces the IRM

[2] Further information regarding the Victorian SIPS battery is at https://aemo.com.au/en/initiatives/major-programs/victorian-government-sips-2020.

will have a similar requirement to ensure the electricity system remains reliable during a 1-in-10 year summer. This is referred to in this Appendix as the 'IRM equivalent'.

The 2020 ESOO will provide detailed and specific reliability assessments using the most up to date input assumptions and should be relied on to determine whether projected USE would exceed either the reliability standard or IRM. The analysis for this ISP, while not as rigorous as the ESOO reliability assessments, is sufficiently sound and robust to assess supply adequacy of the candidate development paths and potential supply scarcity risks for consumers.

This section presents the estimated reliability assessments for the Central and Step Change scenarios. These assessments have been produced using a SRMC Reliability model across nine reference years, each with 10 forced outage samples (in contrast, the ESOO looks at 2000 outage samples to ensure convergence, and tail risks are fully captured).

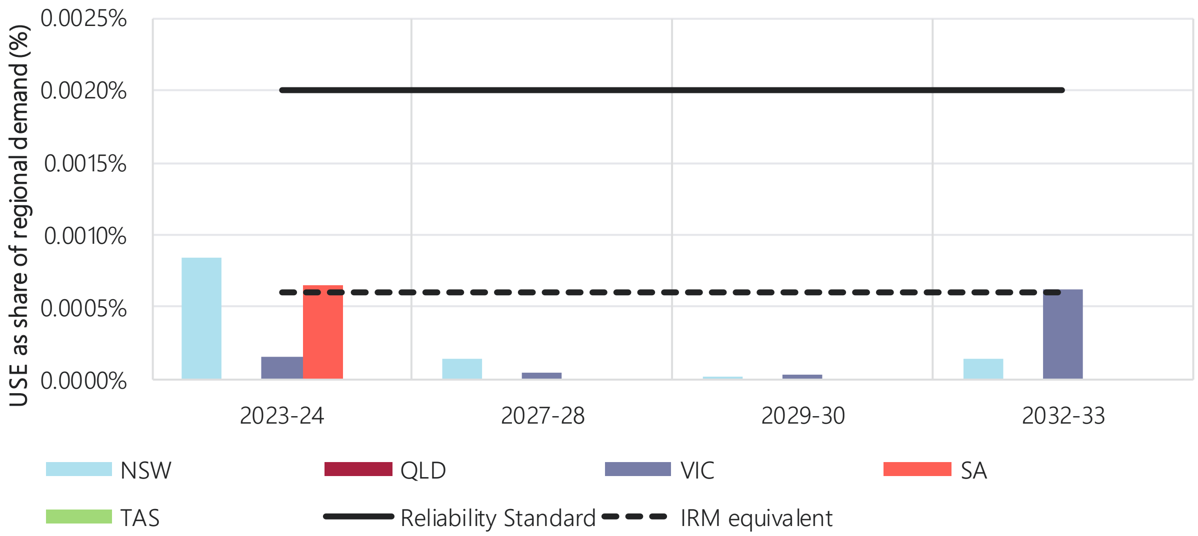
The results shown below are a weighted average of 10% POE and 50% POE[3] simulations and present expected USE outcomes for a sample of snapshot years. These snapshot years have been chosen to present risks introduced by:

- Scheduled capacity withdrawals, and
- A lack of inter-regional upgrades.

Estimated reliability – Central scenario

Figure 3 shows the estimated reliability under the Central scenario, including the network investments associated with the ISP Central scenario least-cost development path. The figure demonstrates the forecast estimated reliability of each NEM region, compared with the reliability standard and IRM equivalent.

Figure 3 Central scenario reliability assessment, snapshot years



As shown in the figure above, the reliability assessment indicates that generation and storage development enabled by the network investment in the least-cost development path is likely to meet the reliability standard in all NEM regions in the snapshot years explored.

The retirements of the Liddell and Osborne power stations in New South Wales and South Australia respectively in 2023-24 are forecast to lead to reliability levels in excess of the IRM in both regions, consistent

[3] POE is the likelihood a maximum or minimum demand forecast will be met or exceeded. A 10% POE maximum demand forecast, for example, is expected to be exceeded, on average, one year in 10, while a 50% POE maximum demand forecast is expected to be exceeded five years in 10.

with findings in the 2019 ESOO[4]. These supply scarcity risks reduce following the commissioning of Project EnergyConnect in the following year.

Following the retirement of Yallourn Power Station in 2032-33, Victoria is forecast to maintain reliability estimates within the IRM with the deployment of the Victorian SIPS battery or equivalent. Without this investment, the IRM may be exceeded.

While these reliability assessments indicate that the Central scenario least-cost development path is reliable, it relies on forecasts of demand, supply, cost and technology uptake to all hold simultaneously. If they don't, the least-cost development path is so tightly optimised that there is little buffer to accommodate variations in the assumptions. In particular, compared to the current system, the least-cost development path is less resilient to

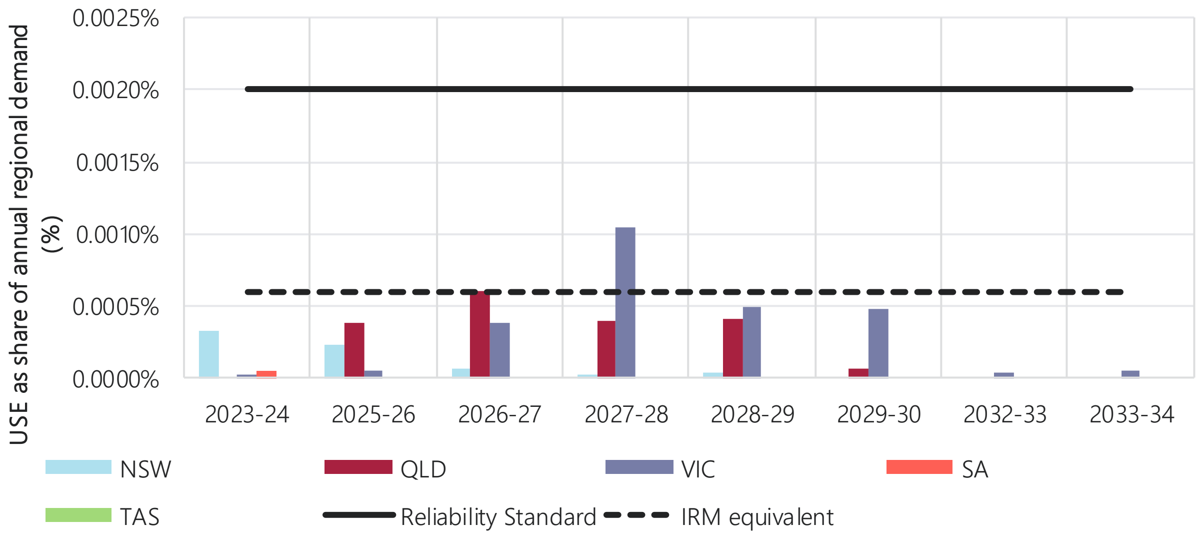
- Early coal retirements.
- Uncertain delivery of large-scale storage.
- Extreme weather events.
- High Impact Low Probability (HILP) events.

These issues are discussed further in this appendix, particularly in Section A6.4.3.

Estimated reliability – Step Change scenario

The reliability outcomes for the Step Change scenario least-cost optimal development path is also presented here, as it represents the most profound change in the power system, of all the ISP scenarios. Figure 4 shows the estimated reliability assessment under the Step Change scenario, including the network investments associated with the Central scenario least-cost development path. The figure demonstrates the forecast estimated reliability of each NEM region, compared with the reliability standard and IRM equivalent.

Figure 4 Step Change scenario reliability assessment, snapshot years



As the figure above shows, the Step Change scenario development opportunities, complemented by the forecast network augmentations, is likely to meet the reliability standard in all NEM regions in the years explored. Due to the accelerated retirement of several black and brown coal generators in the Step Change scenario (in the first 10 years of the forecasting horizon), Queensland and Victoria are forecast to be at higher risk of exceeding the IRM equivalent in 2026-27 and 2027-28 respectively than in the Central scenario. This reduced reliability level in Queensland coincides with the modelled retirement of units at Tarong and

[4] An updated USE outlook will be provided in the 2020 ESOO.

Gladstone power stations driven by the tight carbon budgets assumed in this scenario. Similarly, in Victoria, supply scarcity risks increase following the retirement of units at Yallourn and Loy Yang power stations which are modelled outcomes of this scenario. While market-based dispatchable energy storage is assumed to be developed to help maintain reliability below the reliability standard, more reserves would be required to avoid exceeding the IRM equivalent.

A6.3.2 Renewable generation penetration

Key messages

- The NEM is becoming more exposed to the variability of weather and needs to be designed to be resilient to normal year-on-year variations in weather as well as extreme weather conditions.
- By 2035, the penetration of renewable generation (excluding hydro generation) in the NEM as a proportion of demand is forecast to exceed 85% during certain periods; it may reach 180% in South Australia and nearly 120% in Victoria at certain times.
- Periods of high renewable generation penetration and low demand may pose risks to system security (see Appendix 7), and periods of low renewable generation penetration and high demand may pose risks to reliability (see A6.4.3).
- VRE curtailment in the NEM is forecast not to exceed 4.2% under the Central scenario least-cost optimal development path, although this depends on timely investment in energy storage, transmission networks and associated infrastructure for power system services, and assumes that coal-fired generation can adapt to operate more flexibly than it has in the past.
- Transmission upgrades will help take advantage of geographic weather diversity. However, as distributed and grid-scale PV increases, there will be fewer opportunities to export in high solar periods due to co-incident low demand in all regions (unless exporting to get access to deep storages).
- Although the value of deeper storage in reducing VRE spill is evident, the higher capital cost of additional longer-term storage exceeds the benefits of eliminating spill entirely.

As more renewable generation capacity is forecast to be installed in the NEM, more renewable generation is available to deliver energy to replace retiring coal, but period by period the variability in weather means that the system needs to accommodate periods of very high or very low penetration, and sudden changes from one period to the next.

Figure 5 shows the NEM-wide instantaneous renewable generation per half-hour period, calculated as a percentage share of demand. In this figure, the following definitions apply:

- **Renewable generation** – generation from large-scale wind, large-scale solar and distributed PV (but not including hydro generation)
- **Demand** – end-use customer demand, plus auxiliaries and transmission losses, plus the energy required to replenish storages including pumped hydro, large scale batteries and distributed batteries.

The penetration of renewable generation in the NEM steadily increases across the forecast, and by 2035, it is forecast that there could be periods in which nearly 90% of demand is met by renewable generation – which may trigger investments to maintain system strength and inertia[5]. There is a wide range of potential solutions to the technical challenges that will emerge in this space. See Appendix 7 for more information on this topic.

[5] Apart from system strength requirements in South Australia (see Section A6.4.4 for more information), no explicit system strength or inertia requirements were modelled. The outcomes presented here therefore identify periods in which these issues may present. Appendix 7 discusses these technical challenges further.

Renewable generation penetration forecasts vary across regions, with some regions facing much higher periods of renewable penetration as a proportion of demand than others (see 0). South Australia, in particular, and Victoria to a lesser extent, are forecast to face some periods of renewable generation at levels above 100% of forecast regional demand by 2035. That is, South Australia is forecast to have periods in which renewable generation reaches up to 180% as a proportion of the demand during the corresponding period, and similarly, renewable generation in Victoria in some periods is forecast to reach nearly 120% of Victorian demand. Due to the interconnector augmentations identified in this ISP, high levels of renewable generation in these periods are able to be efficiently exported to neighbouring regions.

Figure 5 Projected cumulative distribution of renewable generation as share of demand to 2034-35, Central scenario, reference year 2013

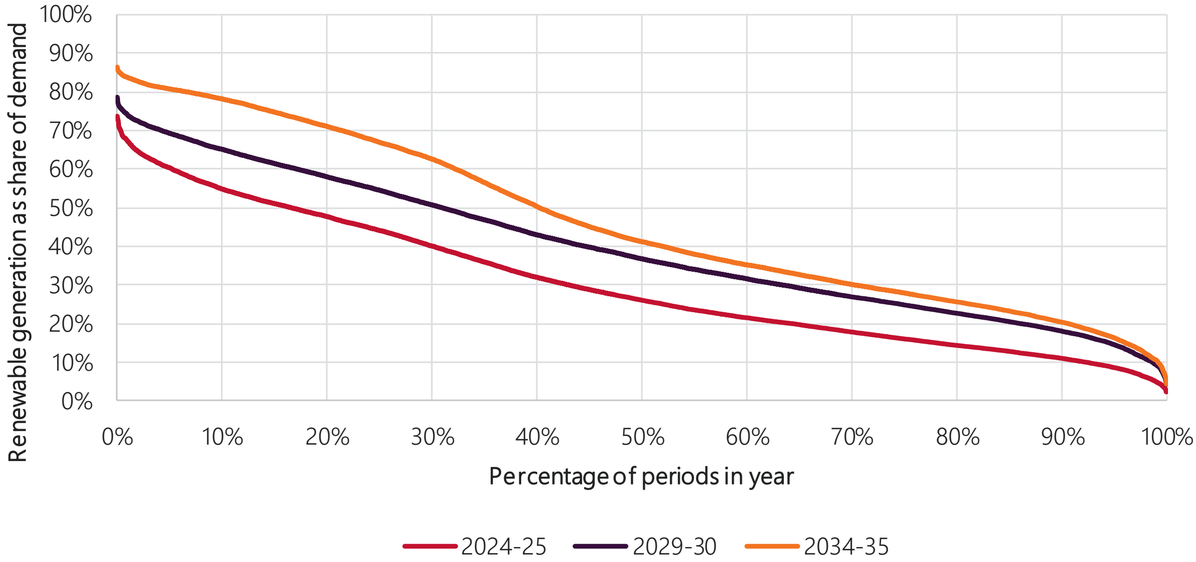


Figure 6 Regional projected cumulative distribution of renewable generation as share of demand to 2034-35, Central scenario, reference year 2013

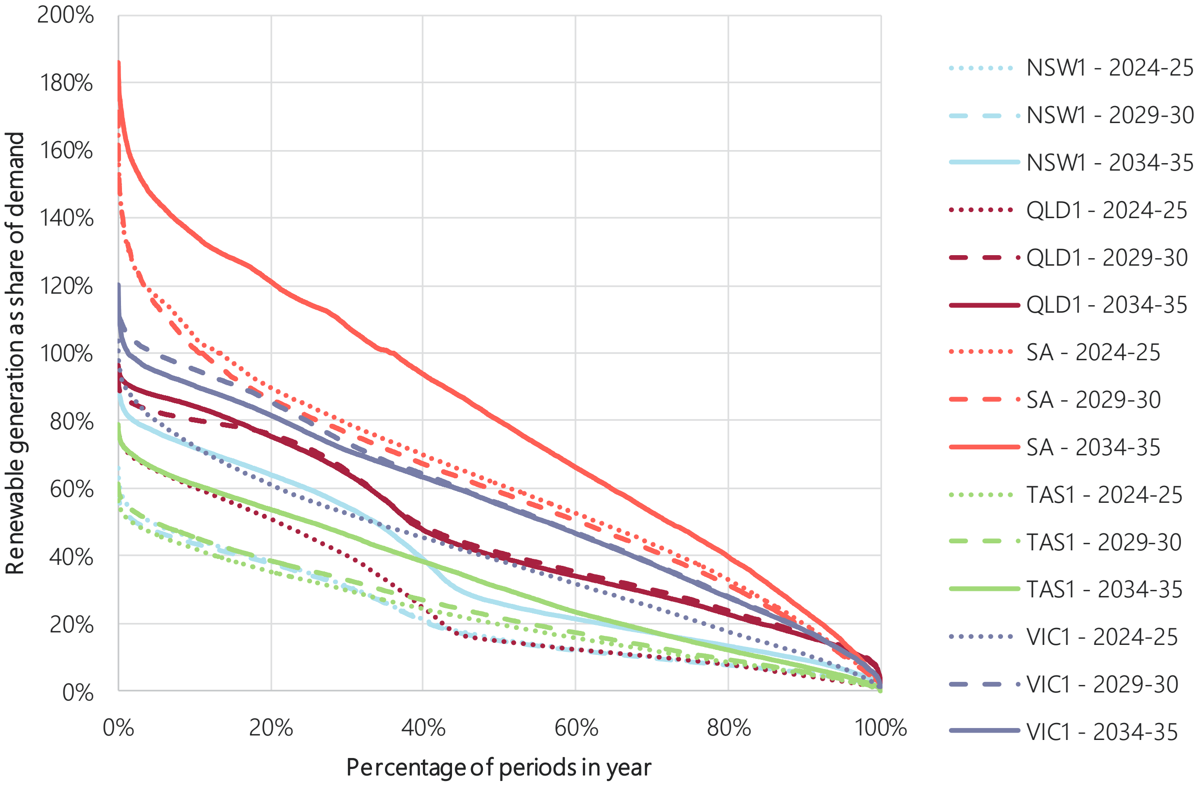
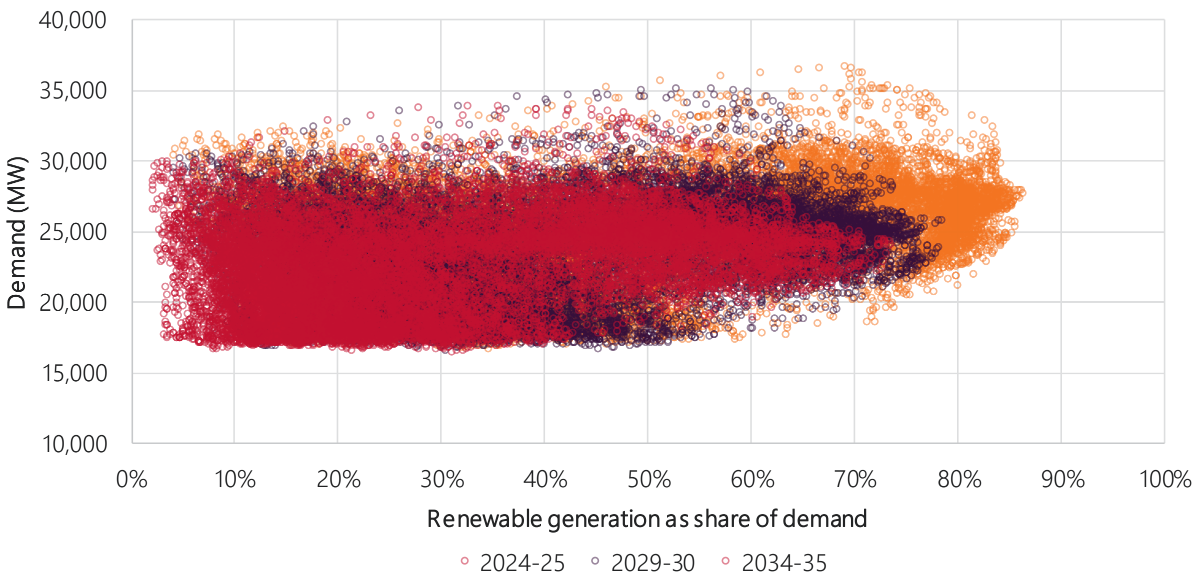


Figure 5 (and Figure 6) show how often periods of high or low renewable generation might occur. Figure 7 shows the correlation of NEM wide VRE generation to NEM wide demand for 2024-25, 2029-30 and 2034-35.

Figure 7 Renewable generation penetration, correlated with demand Central scenario, reference year 2013



For added clarity, Figure 8 was developed from the same data, this time retaining only the "envelope" of renewable generation penetration/demand outcomes to more clearly show the scope of penetration across the forecast horizon.

Figure 8 Envelope of renewable generation as a share of demand correlated with demand Central scenario to 2034-35, reference year 2013

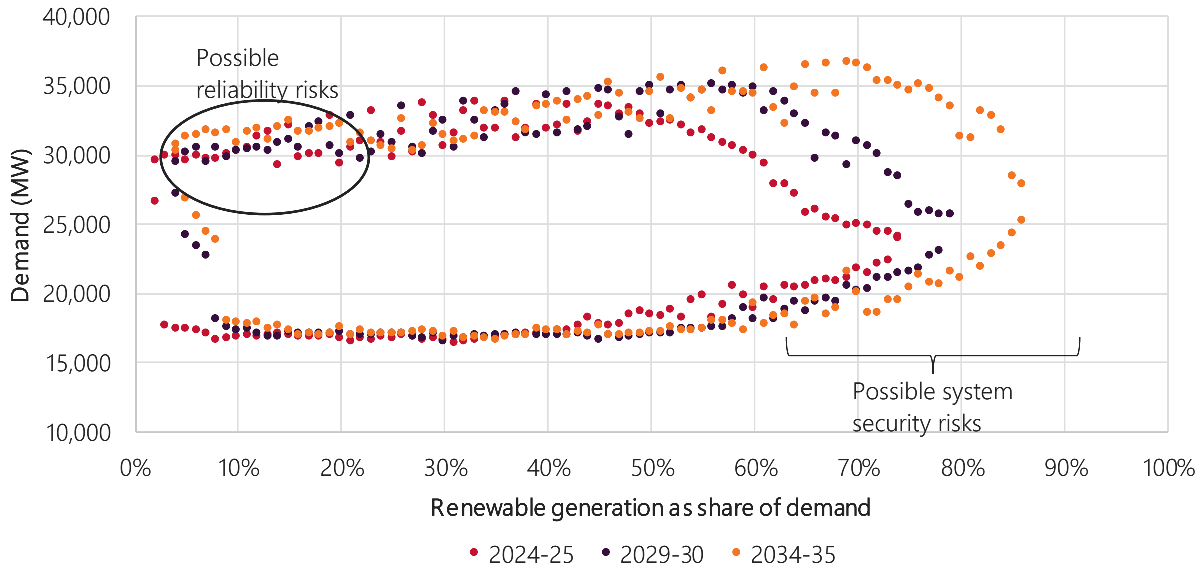


Figure 8 demonstrates the forecast areas of greatest reliability or operability challenge:

- The top left quadrant of the chart shows those periods in which demand is high, yet renewable generation penetration during the same period is quite low. This identifies periods through the year in which there may be limited renewable generation, and the NEM is therefore predominantly reliant on thermal generation to meet demand.
  - While AEMO's indicative reliability assessments of these scenarios suggest that the system's reliability is within the reliability standard, these periods will rely heavily on dispatchable alternatives (coal, GPG, storages, demand response) to meet demand, and also assume that storages have the foresight to sufficiently replenish prior to times of peak demand.
  - Exposure to supply scarcity risk during these periods increases particularly later in the planning horizon, once increasing amounts of coal generation have retired, unless the system is carefully designed to cover these risks. During extended periods of low renewable generation availability, deep energy storages (24-hour and greater) are forecast to play a key role. Storage availability and dispatchability become critical as thermal dispatchable capacity retires.
- Conversely, the lower right quadrant represents areas that may pose concerns to system security or inertia – periods in which demand may be low, but renewable generation penetration is significant. These are the periods in which system strength will need to be carefully managed (see Appendix 7 for a discussion of these issues).

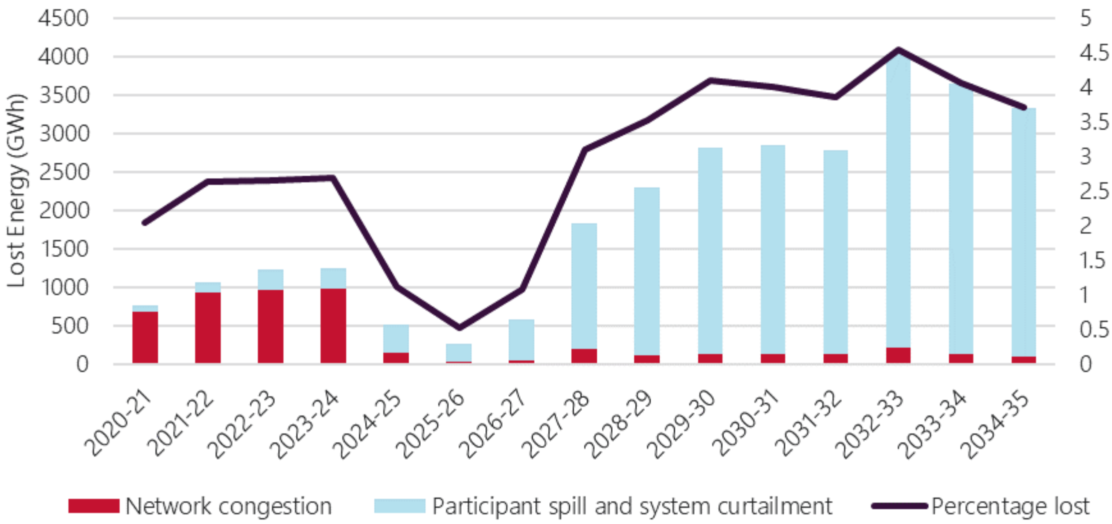
The importance of increased transmission capability between regions heightens over time as more renewable generation capacity is installed, allowing regions to both share the diversity of VRE and share the remaining dispatchable reserves to meet that variability, in particular during times of low generation in a neighbouring region.

VRE curtailment

VRE curtailment, or lost energy, occurs when large-scale solar or wind resources are available, but that available energy is not able to be used by the system.

Despite increasing amounts of VRE, curtailment is forecast to remain low across the ISP horizon (1.2% of total NEM variable renewable generation curtailed in 2024-25, 4.1% in 2029-30, and 3.7% in 2034-35). The ISP co-ordinates generation and transmission development within REZs, so only a small amount of curtailment arises that is explicitly due to congestion of the transmission networks. The exception to this is the South West New South Wales REZ, where existing and committed developments already approach the limits of local transmission capacity; this congestion is relieved when Project EnergyConnect increases the connectivity of this REZ in 2024-25. The remaining curtailment shown in Figure 9 is due to a combination of participant spill (due to low prices) and system curtailment (due to operational constraints such as coal minima and system strength requirements, also characterized by low prices). In both of these cases the available VRE exceeds the system's capability to absorb it.

Figure 9 NEM VRE lost due to congestion and spill, Central scenario, 2021-35 (GWh)



This projection of curtailment demonstrates the value of the REZ development and increased transmission interconnection between the regions as recommended by this ISP. Should timely investment in energy storage, as well as the transmission network and associated infrastructure for power system services, as assumed in the least-cost development path not occur, then curtailment of VRE may reach levels much higher than forecast.

A6.3.3 Coal ramping and flexibility

Key messages

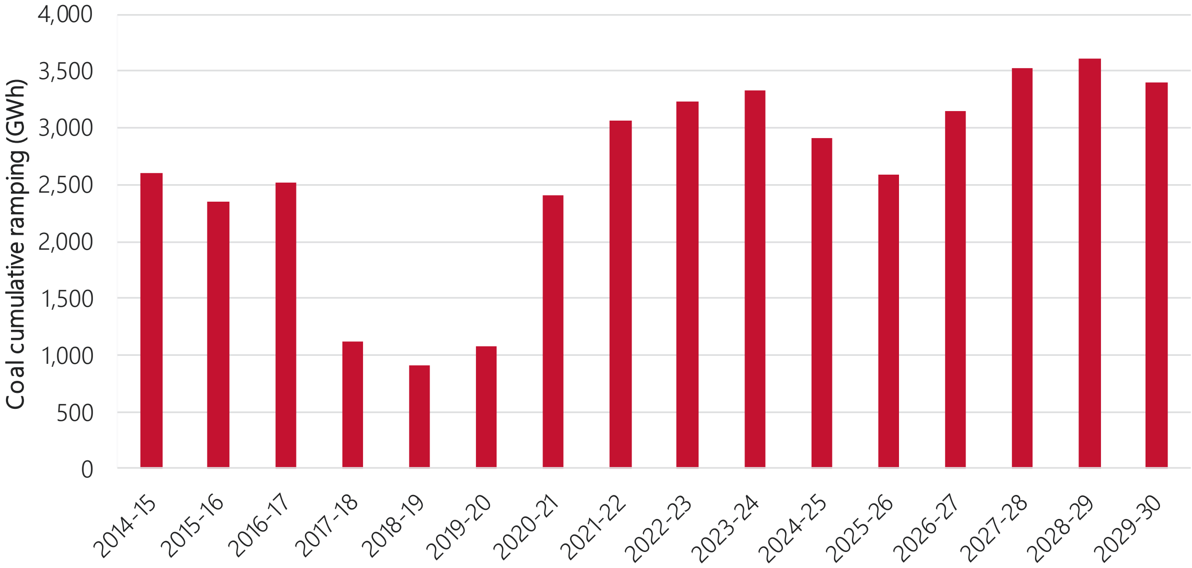
- Efficient integration of renewable generation requires both flexibility from thermal generators and interconnection to accommodate large variations in renewable generation, especially the daily cycling of solar.
- Coal generation units are forecast to vary dispatch levels more frequently and to operate at minimum stable levels much more often than historically observed.
- Challenges may arise for coal plant to further develop their flexibility to turn down output during the day in order to remain competitive and dispatchable as the renewable transition moves forward.

Accommodating large amounts of new renewable generation into the NEM, at times at extremely high instantaneous penetration, will require increasing flexibility from dispatchable generators, including coal generation units.

The time-sequential forecasts incorporate detailed, plant-specific limits for ramp rates and minimum stable levels of operation that units operate within[6].

Figure 10 shows the annual cumulative ramping from Victoria's brown coal-fired generation fleet, both seen in recent history and forecast out to 2030. In this case the cumulative ramping is the sum over a financial year of the MW increase or decrease over every 30-minute period, with start-up and shutdown events excluded from the calculation. As can be seen, the forecast ramping requirements to 2029-30 increase beyond the ramping observed in recent history. While this forecast ramping behaviour is within the bounds of the technical limitations of the Victorian units, it may place further strain on an ageing brown coal-fired generation fleet.

Figure 10 Victorian brown coal-fired generation annual cumulative ramping (GWh), 2014-2015 to 2018-19 (historical), 2019-20 to 2029-30 (forecast)



The black coal-fired generation fleet is not forecast to require annual cumulative ramping beyond recently observed historical behaviour.

Figure 11 shows the average time-of-day generation profile for black and brown coal in selected historical and forecast years. The frequency and duration of ramping events for brown coal generation is forecast to increase, driven by higher renewable penetration.

Similarly, the black coal generation fleet is projected to operate more flexibly, with a day-night cycle being replaced by intra-day cycling between morning and afternoon peaks.

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6 Note that no sub-30-minute modelling has been completed for this ISP. More detailed analysis on fast ramping and response will be part of future work from AEMO's Renewable Integration Study. See: https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris

Figure 11 Black (L) and brown (R) coal average time-of-day generation profile in 2016-17, 2017-18 and 2019-20 (historical) and 2020-21 and 2027-28 (forecast)

These outcomes are underpinned by the modelling assumption that renewable generation will continue to act as a price taker, while coal generation will continue to dispatch strategically. These assumptions result in coal units becoming the marginal generator more often, particularly in the middle of the day. Corresponding electricity prices provide a financial incentive for coal units to adopt more flexible operating regimes.

Victorian brown coal units have adopted a relatively flat operating profile in recent years, but with the influx of new solar developments (incentivised by VRET) these units are forecast to return to a modest amount of daily cycling.

Cycling more regularly or at higher rates than generating units were designed for may result in extra costs due to wear and tear, additional outages for maintenance, or increased failure rates. Whether the coal fleet will collectively operate more flexibly in the future will depend on many factors which are outside the scope of the ISP modelling. Alternative regimes that operators of coal generation might consider pursuing include partial decommitment of units during the shoulder seasons, to reduce wear and tear from cycling and exposure to low wholesale prices.

Minimum operating levels impact renewable curtailment and revenue sufficiency of coal units

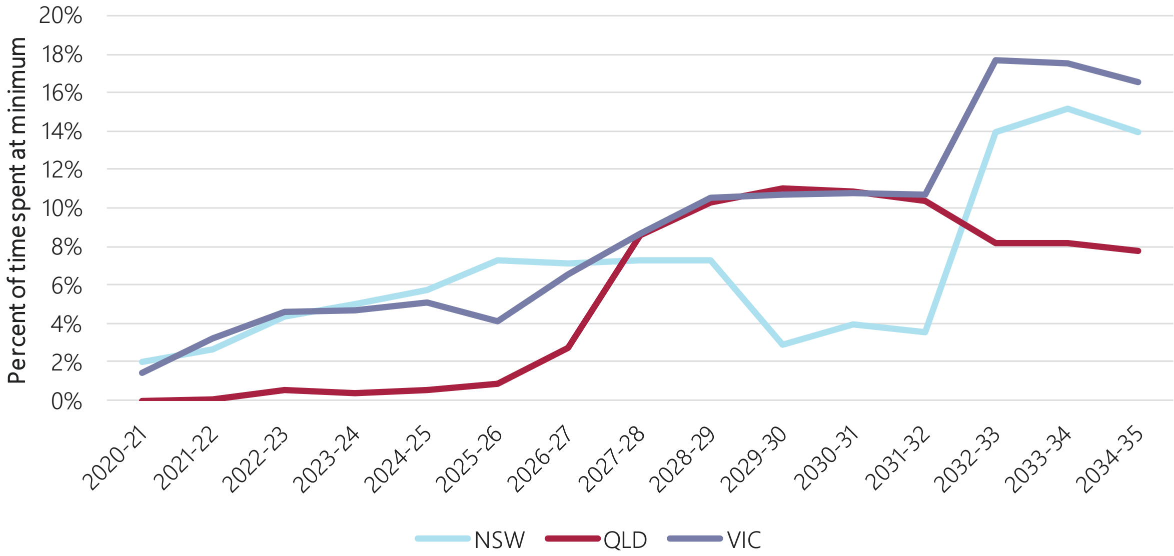
Coal generating units are forecast to operate at minimum stable levels more frequently and may offer generation at prices below the marginal cost of VRE to avoid the need to shut down and restart in a later period.

Figure 12 shows how often entire regional coal generation fleets are forecast to operate at minimum levels. (That is, the percentage of time that all coal generation units that are in service are operating at their minimum stable levels).

The upward trend is primarily caused by the influx of solar generation displacing other sources during the day. Retirements, particularly of Vales Point (New South Wales) in 2029-30, provide some relief to this trend.

Pumped hydro storage within New South Wales is forecast to provide additional flexibility for that region to absorb midday solar. The region also has the advantage of interconnection to two other regions (or three; when the proposed Project EnergyConnect is developed), giving greater scope for sharing excess renewable generation and dispatchable reserves with other regions. Victoria is able to access hydro flexibility in Tasmania via Basslink, but this is limited by the size of that interconnector (unless Marinus Link is developed).

Figure 12 Regional coal fleet time at minimum



Forecast operating regimes for brown coal generation in particular are nearing plant design limits and could lead to deteriorations in reliability. Possible eventualities, not captured in ISP forecasts are:

- Coal units operate through low-price periods at levels above the minimum stable levels assumed. This leads to a spill of wind and solar generation, higher emissions and further erosion to coal generators' revenues due to uneconomic dispatch. For example, analysis revealed that if Victorian brown coal units continue to operate as baseload (that is, at maximum rated capacity whenever in service), net revenues would reduce by 9-15%.
- Coal units ramp up and down as forecast, potentially increasing unit degradation, maintenance costs, and/or unit failure rates, and possibly increasing potential for early retirement.
- Coal units begin to exit the market before the end of their assumed technical life.

A6.3.4 Storage dispatch behaviour

Key messages

- Storage is forecast to create a more dispatchable and reliable system by firming up renewables and smoothing the generation profile of inflexible generation assets.
- Deep storages can take advantage of seasons with modest energy demand and strong renewable availability, and spend more time charging or refilling than generating.
- Shallow storages tend to cycle daily; medium storages are forecast to only achieve a full cycle on approximately 40% of days, whereas deep storages can only ever utilise a small fraction of their capacity in a single day.
- Based on input cost assumptions, building a 4-hour battery storage may become more economical than continuing to operate an existing OCGT unit by 2030.

With significant development of solar generation both behind and in-front of the meter, the role for intra-day energy management to store surplus daytime energy for use during evening demand peaks will increase. This intra-day energy shifting role is forecast to be filled by existing pumped hydro assets as well as a portfolio of shallow, medium and deep storage.

In the ISP, AEMO has defined these dispatchable storage depth classes as:

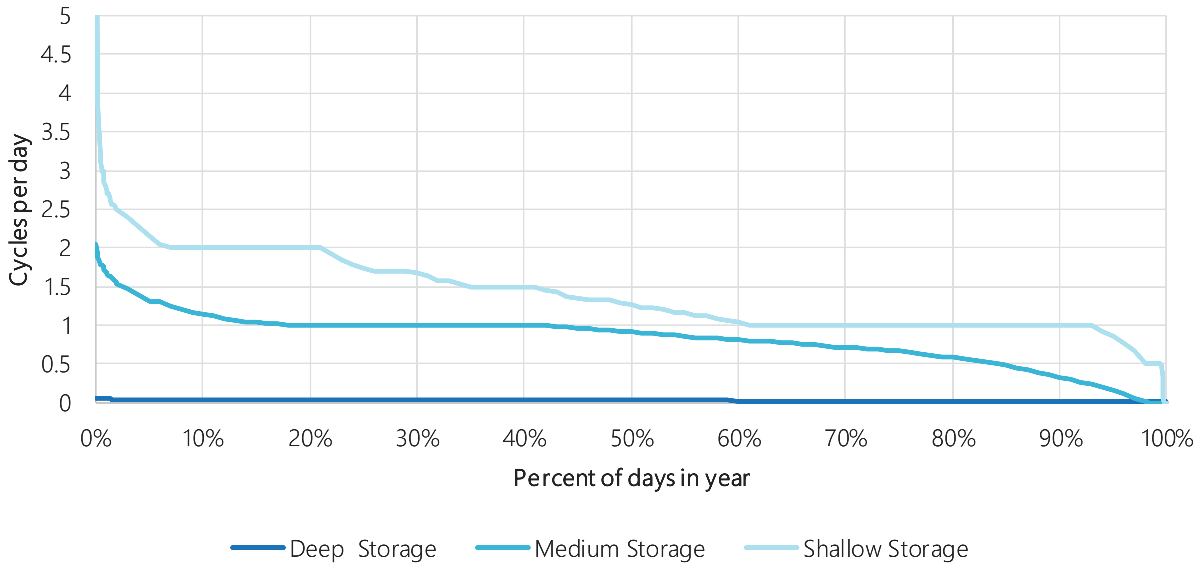
- **Shallow storage** – includes Virtual Power Plant (VPP) battery and 2-hour large-scale batteries. The value of this category of storage is more for capacity, fast ramping, and FCAS (not included in AEMO's modelling) than it is for its energy value.
- **Medium storage** – includes 4-hour batteries, 6-hour pumped hydro, 12-hour pumped hydro, and the existing pumped hydro stations, Shoalhaven and Wivenhoe. The value of this category of storage is in its intra-day shifting capability, driven by demand and solar cycles.
- **Deep storage** – includes 24-hour pumped hydro and 48-hour pumped hydro and includes Snowy 2.0 and Tumut 3. The value of this category of storage is in covering VRE 'droughts' (that is, long periods of lower-than-expected VRE availability), and seasonal smoothing of energy over weeks or months.

Customer batteries that do not participate in VPP are reported separately, as **behind-the-meter storage**. Since they are not dispatchable, their charging and discharging is treated as a component of the demand profiles in the time-sequential modelling.

Daily cycling of shallow storages

Shallow storage systems tend to cycle at least daily. Figure 13 shows the duration curve for the three different depths of storage cycling, as forecast for 2032-33 in the Central scenario.

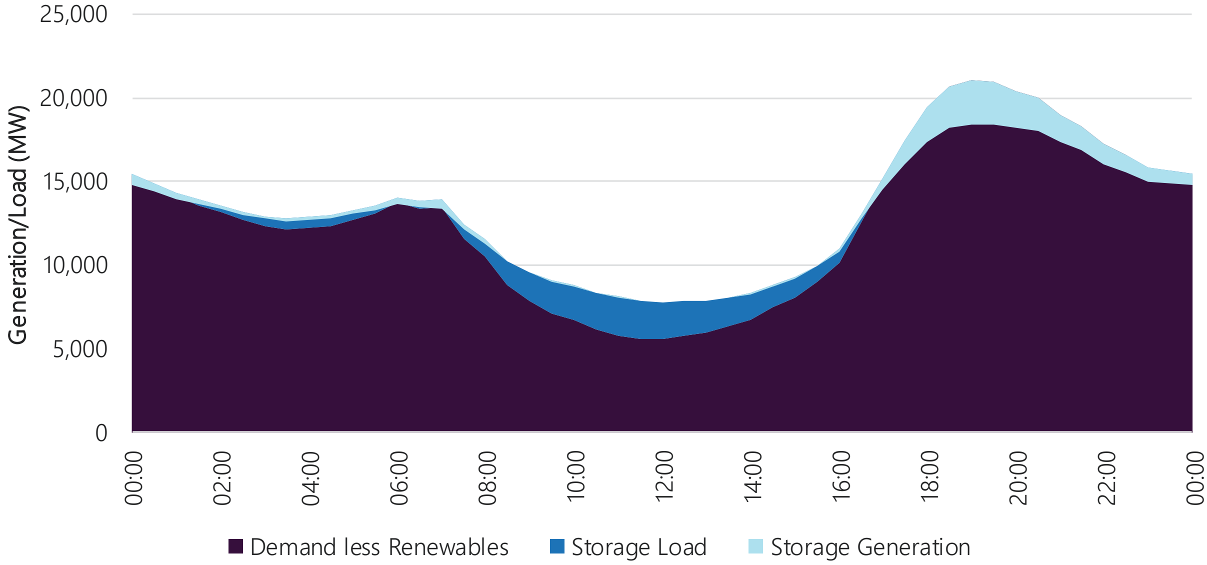
Figure 13 Duration curve of cycles per day in 2032-33 by storage depth



Shallow storages make at least one full cycle on 93% of days, with an extra half-cycle on 41% of days and two cycles on 22% of days. The means the average number of cycles per day for shallow storage is 1.4. For medium storages, three-quarters of a cycle is typical, though a full cycle is achieved on 41% of days (the upper end of this size category includes 12-hour storages, for which one cycle is the maximum possible in 24 hours). Tumut 3 and Snowy 2.0 are the only deep storages in the least-cost development path at this point, and they are so deep that they can only ever fill or empty by a fraction of their capacity in a single day.

The time-of-day dispatch of storages across the NEM is shown in Figure 14, combined with demand minus solar and wind generation to provide an assessment of from the requirement for dispatchable generation. Storages typically charge in the middle of the day, taking advantage of cheap solar, and discharge in the evening to meet the ramp and peak of the evening demand. Where there is excess wind overnight, batteries will charge from this to meet the smaller peak and ramp down of the morning.

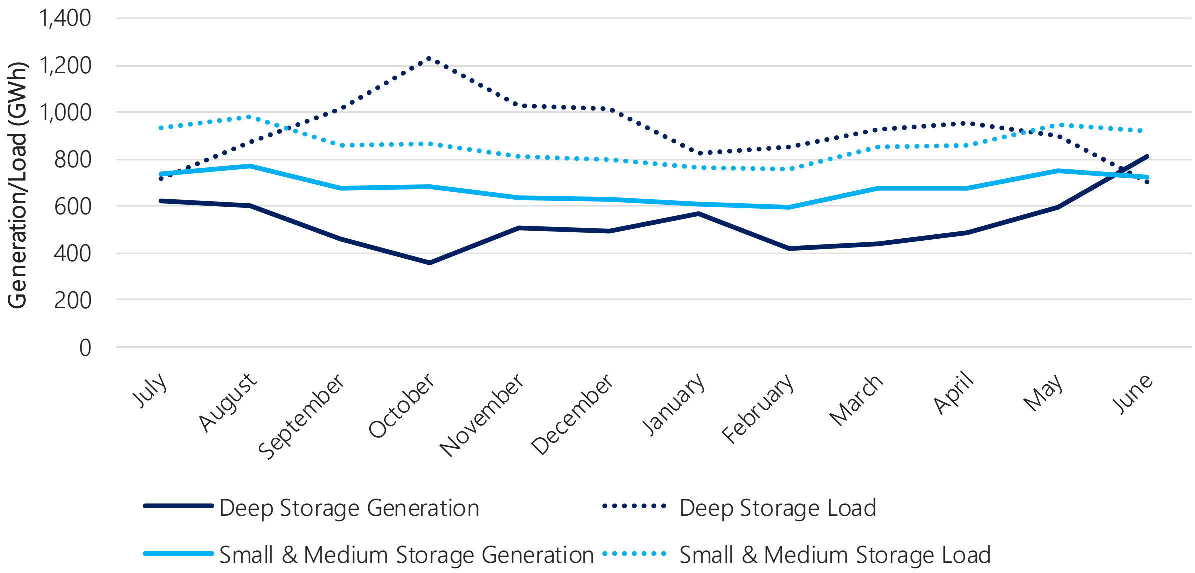
Figure 14 Time-of-day storage dispatch (generation and load) with demand net of VRE, 2032-33



Value of deep storage

While all types of storage are expected to play a key role in the short-term energy shifting, deep storage may provide this service across multiple days, or even seasonally. Figure 15 shows that deep storage absorbs spare energy during the shoulder months to refill the upper reservoirs, particularly during spring, and then generates to meet high demand periods throughout the year. Shallow storage features a much flatter charge/load profile throughout the year consistent with their primary role as intra-day energy shifters.

Figure 15 Storage generation and load annual profile, FYE 2034-35



Provided the market design appropriately incentivises this investment, a portfolio comprising shallow and deep large-scale energy storage systems – with the appropriate transmission infrastructure and complemented by consumer-driven battery systems – will provide an 'all weather' supply mix more resilient to:

- Low renewable energy for prolonged windows (e.g. solar and wind droughts).

- Heatwaves with coincident peak demand levels across regions.
- Partial derating or failure of thermal generators and transmission assets.

Storage economics

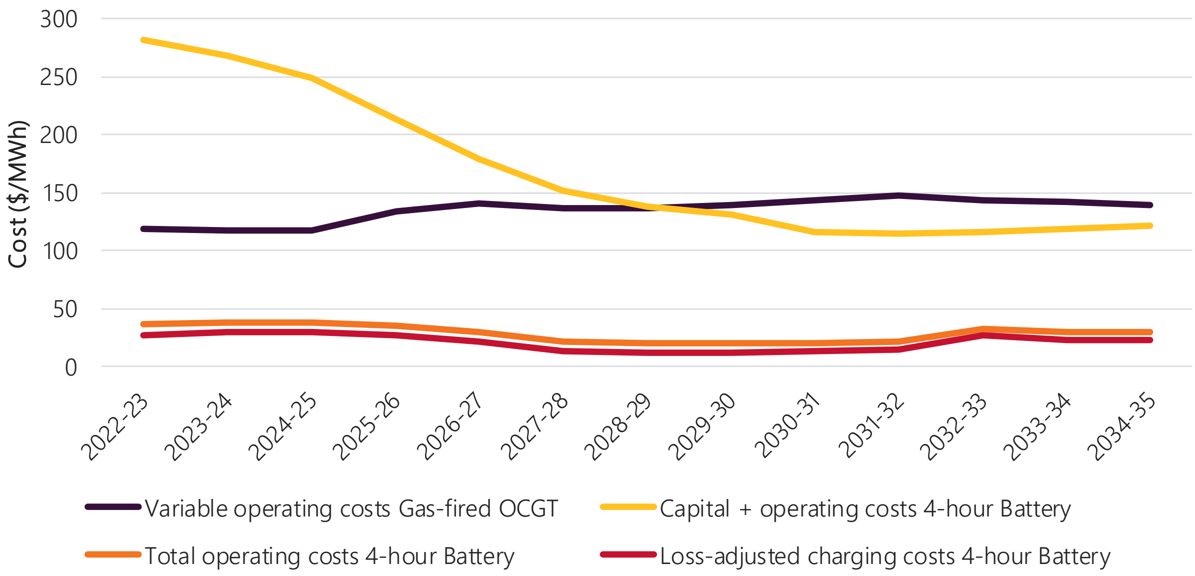
The economics of storages can be broken down into multiple components:

- Build costs.
- Typical market prices during times of charging/pumping.
- Typical market prices during times of generation.
- The capital build costs of batteries are forecast to continue falling (to $922/kW in 2030 for a 4-hour battery, which is half of the current cost).

Typical daytime prices – the time when most storage is charging – is forecast to be set by either coal or renewables. Typical evening prices are fundamentally driven by gas prices as GPG helps to meet evening peak demand periods. Taking these elements into account, with daily operation of around 1.4 cycles, battery storage for energy arbitrage becomes financially viable around 2030, with battery storage to overtake OCGT technology as the cheapest provider of daily peak (if short duration) capacity. This analysis provides a cross-check of the ISP development path and highlights the reason why shallow storage is forecast to be installed to provide firming capacity, instead of new OCGT.

Figure 16 compares the capital and operating costs of a 4-hour battery with the operating costs of an OCGT unit, in Queensland, on a per-MWh basis. The total capital and operating costs (i.e. levelised cost) of the battery becomes cheaper than the variable operating costs of OCGTs (fuel, variable O&M) from 2030 onwards. In that year, the 4-hour battery is assumed to have a capital costs of $112/MWh, fixed operating costs of $7.50/MWh and an average forecast charging cost of $12.50/MWh. OCGT technology has a marginal cost of $139/MWh. From this time, building and operating a new 4-hour battery in 2030 is the cheaper than continuing to operate an existing OCGT unit.

Figure 16 Comparison of capital and operating costs of a 4-hour battery with operating cost of an OCGT unit in QLD, 2023-2035 ($/MWh)



A6.3.5 GPG operation

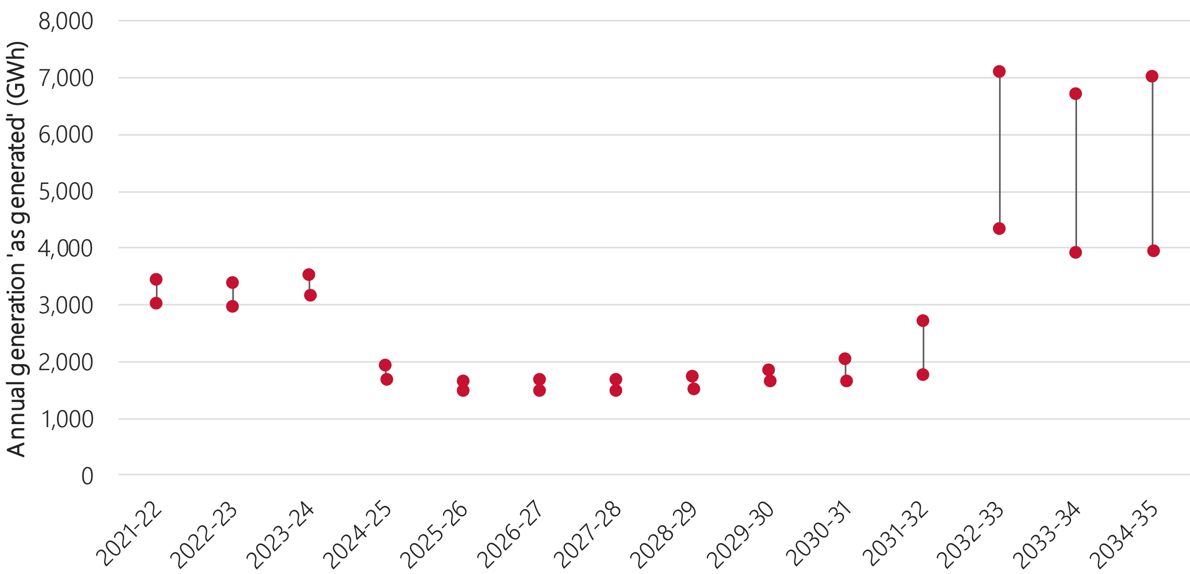
Key messages

- Greater renewable generation penetration will increase the need for availability of a portfolio of flexible generating technologies, including GPG, that can promptly respond to sudden changes in the supply/demand balance and effectively manage weather variability.
- Following the retirement of significant amounts of coal capacity in 2031-32 both the total amount of GPG generation and the level of variability in response to weather is projected to increase, relative to earlier years within the forecast. This also drives variability in total system fuel costs.
- Over the next decade GPG is forecast to face changing time-of-day operational profiles, with highly flexible generators to play a greater role in meeting evening peak demand, and less flexible technologies (such as CCGTs) set to decrease operation in the middle of the day in response to low solar-driven prices.
- Higher reliance on GPG than forecast in the least-cost development path is likely to increase the value of transmission, based on the gas price forecasts consulted on for use in this ISP.
- GPG forecasts vary depending on generators' competitive behaviour assumed. Both the SRMC and bidding models indicate that GPG will decline relative to history. However, the bidding model projects a lower decrease relative to that in the SRMC model due to bidding dynamics reflecting historical behaviour.

As previously discussed in Section A6.3.2, in the future system, with greater VRE penetration, weather variability will have a much greater impact than present. This will increase the need for fast start generating technologies that can promptly respond to sudden changes in the supply/demand balance and effectively manage renewables' intermittency.

The ISP forecasts indicate that existing GPG, complemented by shallow storage, will deliver this increasing flexibility, particularly after the next announced coal retirements. The maximum and minimum forecasts of GPG generation presented in Figure 17 show variance across different weather patterns.

Figure 17 Projected GPG generation across a range of reference years (in the SRMC model)



Weather variability will drive renewable output and in turn determine the profile of the residual demand to be met by dispatchable generation. As significant amounts of coal capacity retire from 2031-32, GPG (largely CCGTs) will play a much stronger role in compensating for low-renewable conditions, thus increasing the variance across reference years. No new GPG builds are forecast to be required under the Central scenario least-cost development path.

Despite the reduction in total energy production, the importance of GPG in providing a form of dispatchable capacity, inertia and system security services cannot be understated. GPG as a generation technology transitions to a role of supporting VRE and storage technologies when the latter is unavailable – for example to help meet evening peak demands once solar generation declines, or overnight under low wind conditions, and provide support during extended high demand periods when shallow storages may only be available for limited durations. GPG also retains a role for providing system strength to each region, which will become increasingly valuable as coal generators retire.

The NEM also faces changing time-of-day GPG generation patterns. The volume of new VRE capacity forecast to be installed in the NEM by 2024-25 is projected to reduce the NEM's reliance on GPG throughout the day, with just a small peak in the evening. By 2035, GPG is not only expected to have increased further; its operational profile is also expected to have changed significantly as more renewable generation (particularly solar in the middle of the day) is forecast to depress prices, which in turn will depress volumes of GPG at those times. This would lead to increased ramping needs and the rate at which ramping is required at peak times, both morning and evening.

The role of GPG in the future will critically depend on the timely development of renewable generation, different types of storages, and development of transmission to maintain reliability while other forms of dispatchable power are withdrawn. The level of GPG forecast under the least-cost development path does not raise any material concerns for the gas system (as long as further field development and infrastructure expansion continues, as flagged in Appendix 10, and the 2020 Gas Statement of Opportunities (GSOO)[7]) or more broadly for the NEM fuel security.

Greater GPG would, however, translate into higher system fuel costs over the study period and higher carbon emissions, increasing the value of new transmission to share lower cost, lower emission generation sources more efficiently across the NEM. If lower cost sources of generation are not available or accessible to displace gas (as in the counterfactual) this could have implications for supply affordability. Additionally, a system relying too heavily on gas for electricity generation, given the gas supply challenges, may pose a risk to supply adequacy.

GPG forecast when considering strategic dynamics

GPG contributed approximately 10% and 8% of generation in the NEM in 2017-18 and 2018-19, respectively.

There is a forecast decline in GPG over the next decade, mainly due to increased renewable generation capacity in the NEM to meet various decarbonisation and energy policies set by Commonwealth and state governments, as well as new storage builds. During this time, domestic gas prices are also projected to materially increase, lowering the competitiveness of GPG.

In addition, the ability of NEM regions to share resources (in particular, geographically dispersed VRE) would increase upon commissioning of new transmission projects. This, in turn, is forecast to reduce the need for generation from GPG, particularly while gas prices are high.

GPG forecasts vary depending on generators' competitive behaviour assumed. Figure 18 shows projected GPG generation for the Central scenario least-cost development for the first decade of the ISP horizon (2021-22 to 2031-32). The two trajectories compare outcomes under SRMC with unit commitment assumptions and strategic bidding behaviour. Both the SRMC with unit commitment and bidding models indicate that GPG will decline relative to history.

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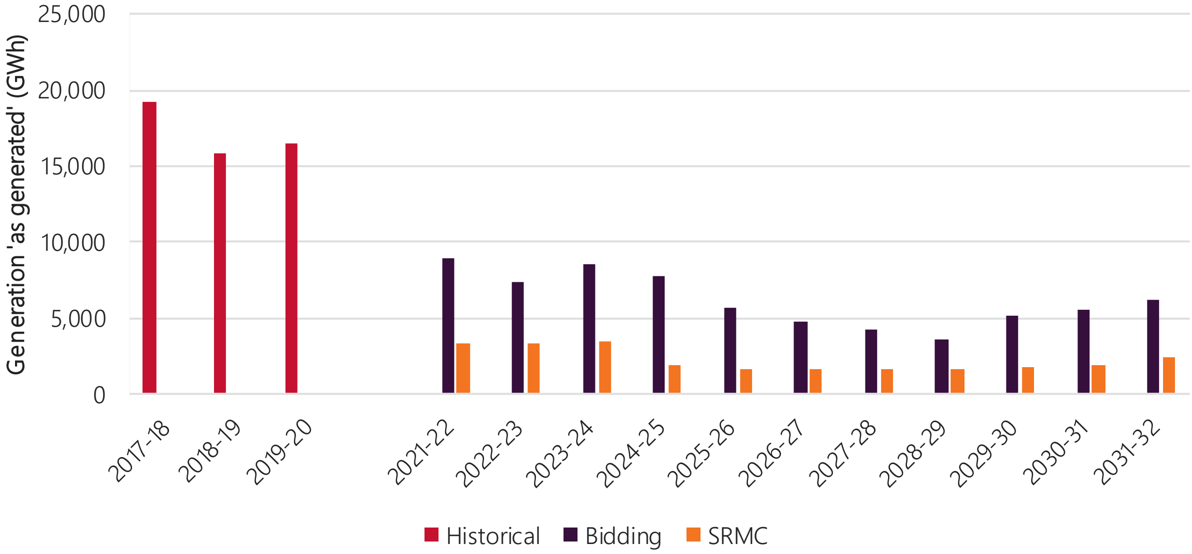
[7] Available at: https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

However, the bidding model projects a lower decrease relative to SRMC assumptions. While unit commitment constraints and complex heat rates produce a realistic dispatch pattern for GPG, particularly for less flexible technologies such as CCGTs and gas-fired steam turbines, strategic bidding drives GPG levels above and beyond least costs levels due to competition dynamics reflecting historical behaviour. These ISP GPG forecasts should only be treated as an indication of forecast GPG behaviour. For more detailed and rigorous GPG forecasts, refer to the 2020 GSOO.

Figure 18 Historical and projected GPG in bidding and SRMC model



A6.4. Regional risks and insights

AEMO has provided a number of targeted, regional-specific cross-checks using detailed half-hourly models to help inform selection of the development path that meets the ISP and policy objectives. This section:

- Highlights key evolutionary considerations for the development and operation of systems in NEM regions, building on the NEM-wide discussion in Appendix 4.
- Provides an overview of the key REZ policies for each region.
- Provide a broad overview of regional operability challenges, risks and opportunities.

A6.4.1 Queensland

Key messages

- Queensland is forecast to build 4.2 GW of new VRE capacity by 2029-30 (in addition to committed and anticipated projects), and in line with observed national trend, is forecast to face the challenges of operating a system in both periods of very high and very low VRE.
- Under the Central scenario, Queensland maintains an energy surplus which is exported to New South Wales. In the Step Change scenario, Queensland's coal fleet is assumed to retire earlier than in the Central scenario, and QNI is forecast to flow northward more frequently.
- Increased import and export capacities of the QNI augmentations are expected to be utilised under both Central and Step Change scenarios.

The Queensland Renewable Energy Target (QRET) of 50% VRE by 2030 is forecast to require approximately 5,100 MW of additional large-scale renewable generation capacity in Queensland. Of these additions, approximately 900 MW is expected to come from anticipated projects (Broadsound Solar Farm, Cape York Battery Power Plant – Solar, and Macintyre Wind Farm), while the remaining gap of 4,200 MW is forecast to be located in the Far North Queensland, Isaac, Fitzroy, and Darling Downs REZs (for further information, see Appendix 5).

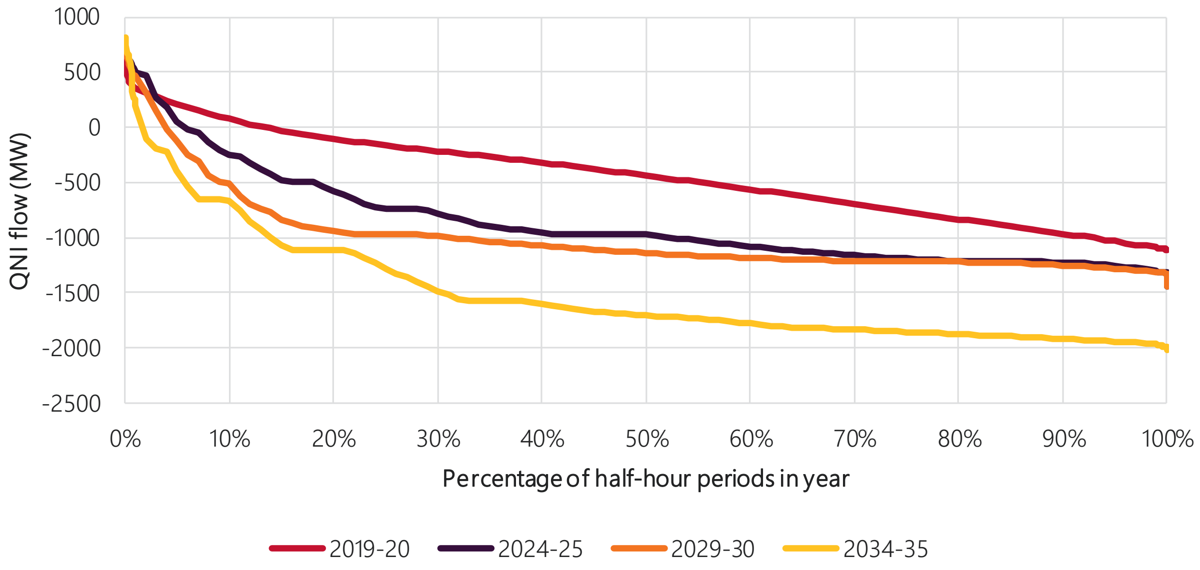
In addition to the QRET, the Queensland region is forecast to undergo many changes over the coming years. Progressive retirement of the existing coal fleet is anticipated, with 700 MW retiring by 2030 (based on expected closure years provided by participants), and a further 3,530 MW by 2042. Queensland is still forecast to retain its coal generation the longest of any NEM region, with plenty of traditional firm, baseload capacity available. Storage is forecast to impact the Queensland energy outlook in the long term, with approximately 650 MW of large-scale battery and/or pumped hydro storage built by 2034-35, and about 3,350 MW by 2041-42. Queensland is also forecast to continue increasing the amount of VPP and behind-the meter storage, with around 675 MW anticipated by 2041-42.

The coal fleet will have to adapt its operation for the system to accommodate new renewable generation, but the region will continue to have a substantial energy surplus for years to come.

Forecast network performance

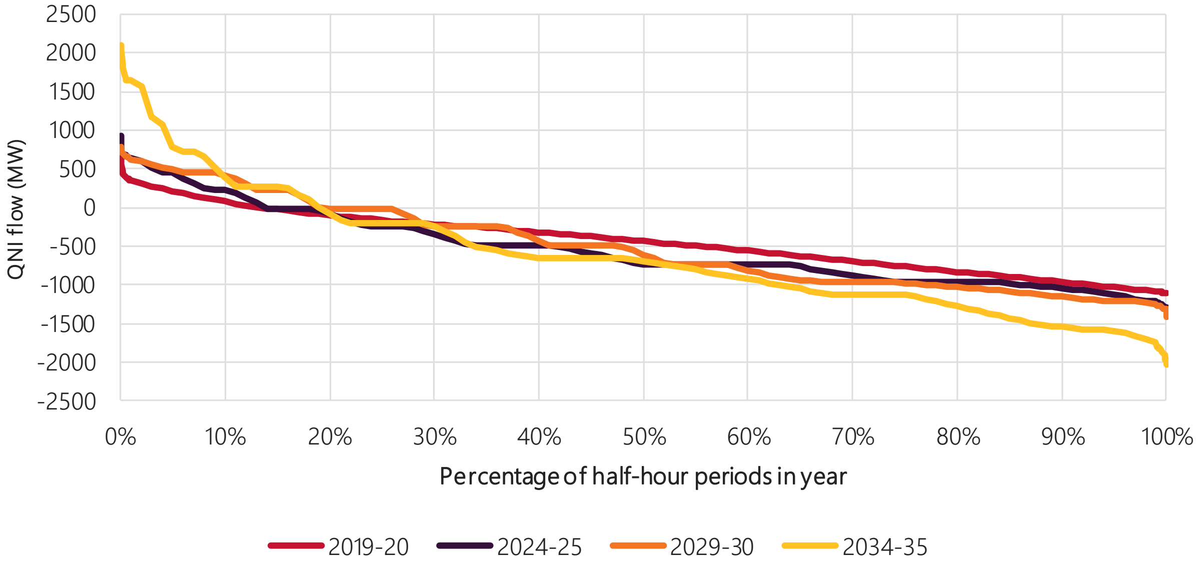
Figure 19 shows the historical and forecast operation of QNI. Queensland exported its energy to New South Wales over 85% of the time during the 2019-20 financial year. It is forecast that this predominantly export behaviour will continue, with the minor (July 2022) and major (July 2032 to July 2035) QNI expansions increasing the capacity to export energy southward even further. This is driven by Queensland's younger coal fleet and increasing development of the region's strong solar and diverse wind resources.

Figure 19 QNI flows, Central scenario least-cost development path, 2019-20 (historical), 2024-25, 2029-30, 2034-35 (forecast)



The least-cost development path from the Step Change scenario sees half of Queensland's coal fleet retire by 2030-31 to help meet the strict carbon budgets to 2050. While it is projected to be broadly replaced by local wind and solar developments, some VRE capacity is also installed in New South Wales to offset these closures, leading to a more balanced flow across the transmission lines with New South Wales. Figure 20 shows the interconnector being used to share firming capacity and renewable energy between the regions more frequently bi-directionally in this scenario, rather than to export baseload power. By 2035, during small periods of time, both regions are forecast to take advantage of both the increased import and export capacities of the QNI augmentations.

Figure 20 QNI flows, Step Change scenario, 2019-20 (historical), 2024-25, 2029-30, 2034-35 (forecast)



Estimated reliability risks

As described in A6.3.1, there are no indications of reliability risks for Queensland under the Central scenario, provided the market-based development opportunities identified in this ISP proceed as forecast.

Under the Step Change scenario, due to major capacity withdrawals prior to 2030-31 resulting from modelled retirement of black coal plants, Queensland is estimated to experience periods of USE but not to the extent that would indicate an exceedance of the IRM equivalent or the reliability standard (see Figure 4). In this scenario, there is some supply scarcity risk identified for 2026-27 as this indicative reliability assessment suggests Queensland may only just meet the IRM equivalent in that year, and may require procurement of additional reserves under the RRO should USE exceed 0.0006%.

A6.4.2 New South Wales

Key messages

- New South Wales is forecast to continue to rely heavily on imports from neighbouring regions across the ISP horizon to meet demand, even as the generation mix in the NEM changes.
- Even during times of high VRE, New South Wales is forecast to often import its energy from other regions, using periods of excess energy to refill deep storages in the region.
- Additional VRE installed in New South Wales, above that assumed in the least-cost development path (such as in the Central-West Orana REZ market event sensitivity), may lead to coal intra-day decommitment, mothballing, or other changes to coal operating profiles.

As the generation mix in the NEM is forecast to change over the ISP outlook[8], New South Wales is forecast to continue to rely heavily on imports from neighbouring regions (Victoria, Queensland and South Australia once Project EnergyConnect is commissioned) to meet forecast demand.

Figure 21 shows the net imports into New South Wales from 2021-22 to 2035-36, showing that every year in the outlook, New South Wales imports more energy than it exports, with the region able to take advantage of excess renewable generation in neighbouring regions to refill deep storages. With the demand in New South

[8] See Appendix 5 for an assessment of the REZ development within New South Wales.

Wales forecast to be between approximately 65,000 – 75,000 GWh per annum, this equates to roughly 1/6th of New South Wales demand being met by imports each year in the Central scenario.

Figure 21 New South Wales annual net imports and underlying demand, 2021-22 – 2034-35

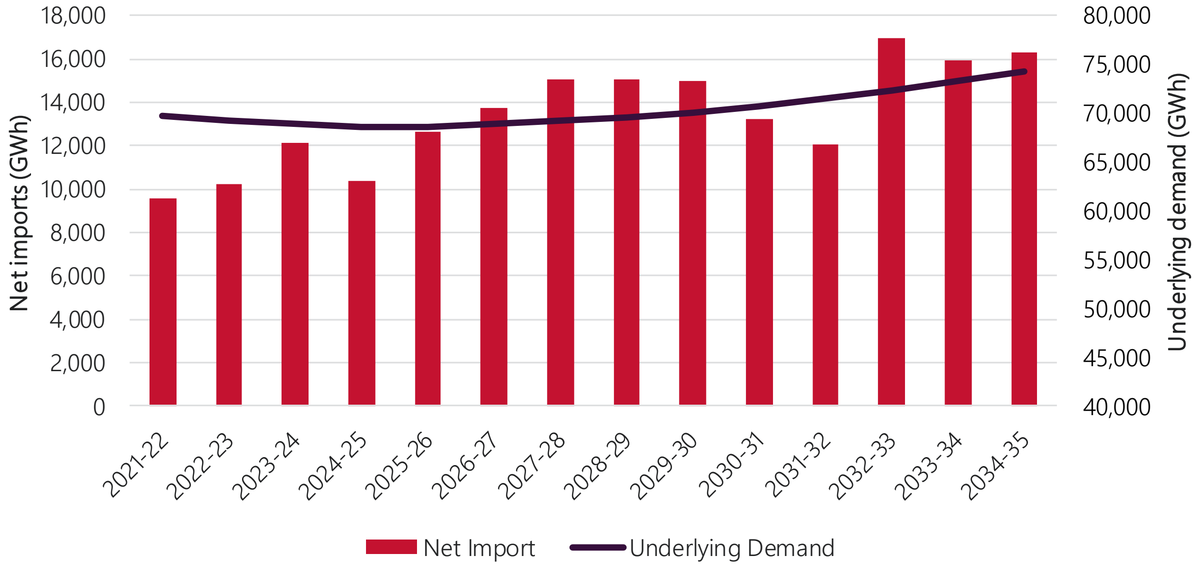
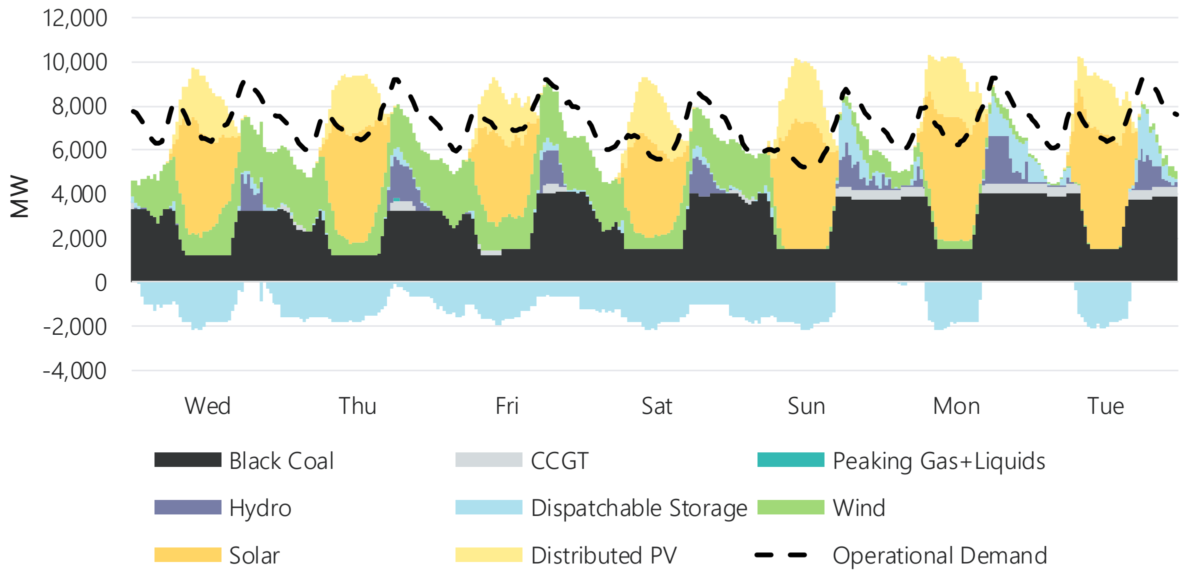


Figure 22 provides an example of the changes expected to be experienced by the New South Wales generation fleet, taken from a forecast sample week of sustained periods of high renewable generation in 2032-33. In this case, operational demand is met by a combination of VRE generation, baseload generation and imports (with imports filling in the white space in the figure). Complementary support from GPG is provided during evening peak periods.

Figure 22 Week of high VRE in New South Wales, 2033



Snowy 2.0 notably takes advantage of excess VRE to fill its deep storage for most parts of the week (representing the majority of dispatchable storage in the figure) and discharges the stored energy in the last few days to support both Victoria and New South Wales during peak demand periods.

Transmission developments that are forecast to be commissioned in 2035-36 (QNI large and VNI West) would further improve interconnection of New South Wales with neighbouring regions, and thus enable greater flexibility in managing supply scarcity risks.

Central-West Orana REZ VRE development

New South Wales Government's first pilot REZ developments in Central-West Orana demonstrate the intent for major renewable energy developments to offset the need for generation from traditional thermal sources. The investment in transmission network needed to accommodate 3 GW of large-scale VRE in the Central West REZ has been assumed in all scenarios and candidate development paths. Additionally, the total development of the generation sources within the REZ is determined by model optimisation.

This section considers the impact of developing the additional 2 GW of VRE in Central-West New South Wales sooner than forecast in the Central scenario. In this market sensitivity, the VRE is progressively deployed from 2024-25 to 2027-28. Appendix 4 investigates this development in more detail.

Forecasts of VRE curtailment in this REZ remain below 1.5% confirming that the transmission capacity enabled by the Central-West Orana REZ Transmission Link is sufficient to accommodate the additional 2 GW by 2027-28 within the Central-West Orana REZ.

These large quantities of new VRE in New South Wales in the next decade could potentially increase the amount of time the coal-generation fleet operates at minimum stable level, and exert downward pressure on the regional price particularly in the middle of the day when there are significant amounts of solar generation.

As mentioned in Section A6.3.3 (Coal ramping and flexibility), this could lead to:

- Reduced net revenue from the New South Wales coal-fired generation fleet.
- The coal generation fleet retaining their historical operating regimes, thus curtailing and reducing the value of the new VRE.
- The coal generation fleet responding to the low prices by shutting down in the middle of the day, seasonably mothballing or retiring early. Analysis suggests that flexible operation of this nature could potentially be a profit maximising strategy for the New South Wales coal generation fleet. An early retirement of brown coal in Victoria would improve the outlook for New South Wales coal generation in this sensitivity, and vice versa.

New South Wales reliability and regional operability

New South Wales is likely to experience tight supply-demand conditions in the years when orderly retirement of major coal plants – such as Liddell, Vales Point and Eraring power stations. Figure 3 shows expected USE is forecast to remain below the reliability standard, provided the ISP actionable and future projects and development opportunities proceed as forecast. There could be further risks to reliability within New South Wales if:

- There is a delay in the start date of Snowy 2.0 and/or HumeLink is not developed.
- Project EnergyConnect is not developed.
- Coal generation retires earlier than planned or becomes increasingly unreliable as the fleet ages.
- The ISP future project requiring preparatory activities ahead of ISP 2022 to reinforce Sydney, Newcastle and Wollongong is not progressed (see Appendix 3).

A6.4.3 Victoria

Key messages

- While the Central scenario least-cost development path has been assessed to be reliable, risks and uncertainties exist concerning the resilience of the system to this development path, including early coal retirement, high impact low probability events, extreme weather events or changes to demand forecasts.
- The resilience of the Victorian system can be increased through further or earlier interconnection between regions, such as bringing forward the development of VNI West.

Approximately 11,195 MW of renewable generation is required to meet the Victorian Renewable Energy Target of 50% VRE by 2029-30. 0 and Table 2 list projects and the sources of capacity that contribute to achieving the VRET by 2029-30. The contribution of each source is relatively equally distributed, where the additional capacity represents 27% of total capacity, followed by assumed DER (26%), committed and anticipated (24%), and existing VRE in 2020-21 (22%).

Table 1 Committed and anticipated projects in Victoria by 2029-30

Category	Project	Capacity
Committed projects	Bulgana Green Power Hub Wind Farm	204
	Cherry Tree Wind Farm	58
	Dundonnell Wind Farm	336
	Elaine Wind Farm	84
	Moorabool Wind Farm	312
	Stockyard Hill Wind Farm	532
	Kiamal Solar Farm stage 1	200
	Yatpool Solar Farm	94
	Cohuna Solar Farm	31
	Winton Solar Farm	85
Anticipated projects*	Berrybank Wind Farm	181
	Berrybank Wind Farm - Stage 2	151
	Murra Warra Wind Farm - Stage 2	209
	Carwarp Solar Farm stage 1	100
	Mortlake South Wind Farm	158
Total committed and anticipated projects		**2,735**

* Anticipated projects, as defined in the draft AER CBA guidelines, are projects in the process of meeting at least three of the criteria for a committed project and are included in all candidate development paths and the counterfactual.

Table 2 Capacity contribution to VRET by 2029-30

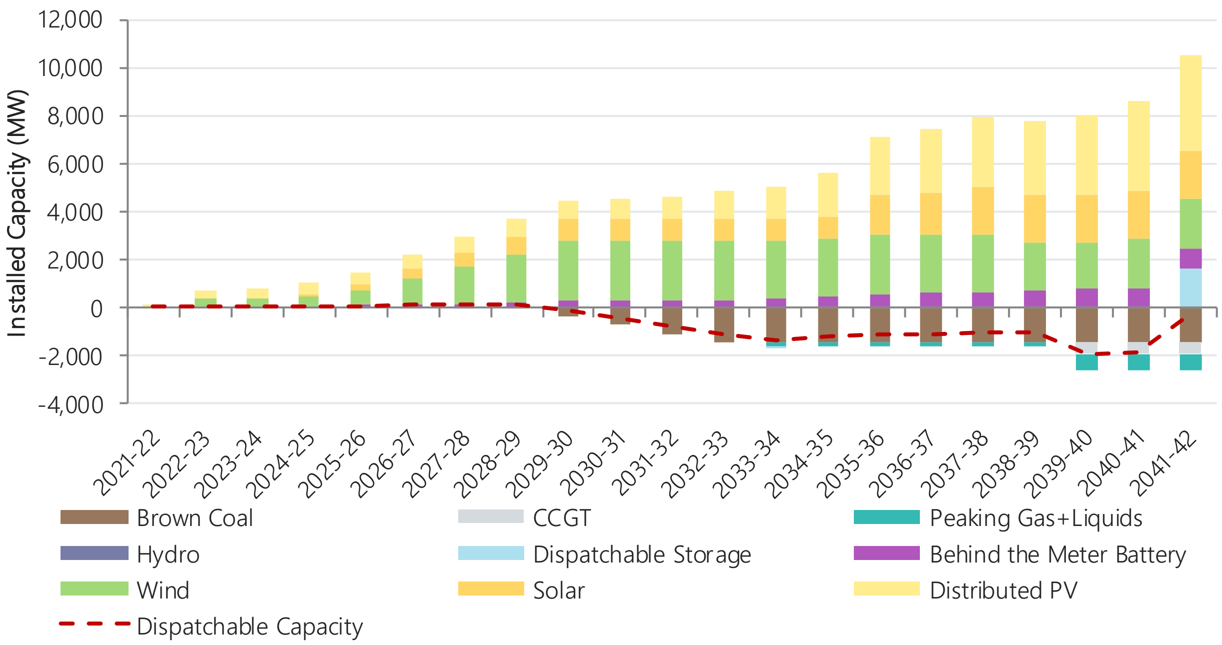
Category	Capacity (MW)	Percentage of total VRE capacity (%)
DER	2,960	26%
Existing VRE	2,461	22%
Total committed and anticipated projects	2,735	24%
Additional VRE	3,040	27%
Total VRE Capacity	**11,195**	**100%**

The Central scenario least-cost development path forecasts that electricity demand in Victoria can be met by local dispatchable and behind the meter generation resources, and existing interconnectors until major coal retirements across the NEM occur in 2035.

Figure 23 below shows the forecast change in the capacity mix for Victoria in the least-cost development path for the Central scenario, taking into account both new builds and retirements. New VRE developments are forecast to add 2,100 MW of wind capacity (excluding anticipated projects) and 900 MW of large-scale solar capacity to the system by 2029-30 in this scenario. Development of renewable generation capacity in Victoria to meet the VRET will largely offset lost supply from the progressive closure of Yallourn coal power station units from 2028-29 to 2031-32, complemented by small amounts of dispatchable storage.

Further VRE development beyond the VRET is not expected until the mid-2030s when further coal retirements create a need for additional generation capacity. This additional VRE is complemented by an increase in large-scale battery capacity of 1,690 MW by 2041-42.

Figure 23 Forecast cumulative changes to Victorian generation capacity to 2041-42, Central scenario



In the Central scenario least-cost development path, Victoria meets both the reliability standard and IRM equivalent, as mentioned previously in Section A6.3.1 (Figure 3). However, this relies on new dispatchable capacity, much of which is less flexible than the thermal generation it will be replacing. While modelling, which has the benefit of perfect foresight, shows that the system can be operated reliably provided all assumptions hold, in reality, when working with imperfect information, the operability of the system is likely to become more challenging.

Risks and uncertainties exist concerning the resilience of the system to this development path, including:

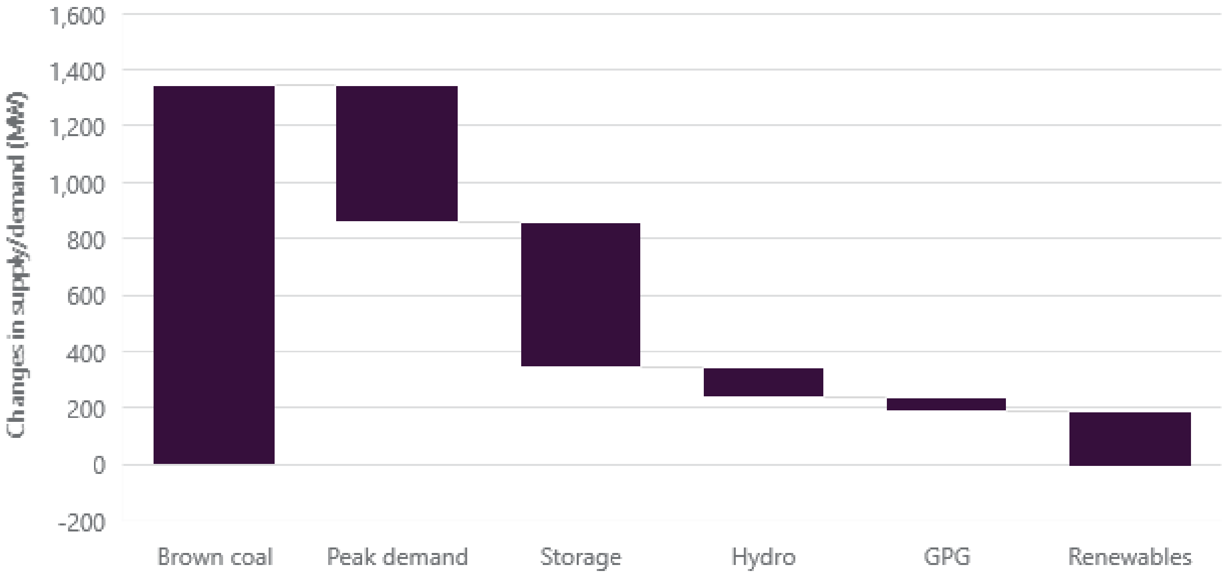
- Early retirement of brown coal generation.
- HILP events such as an extended outage on Basslink (of up to six months).
- Extreme weather events.

In the event the entire Yallourn power station retires earlier than announced (2027-28), Figure 24 shows how this capacity is forecast to be covered during peak demand conditions, relative to the supply-demand outlook of today. The impact of the loss of brown coal capacity is primarily offset by the projected decline in peak demand, uptake of dispatchable storage (525 MW across Victoria and South Australia combined, including VPP) and increased VRE contribution to peak demand. Supply from existing firm generation sources such as hydro and GPG is only expected to increase marginally, driven by small capacity upgrades and reductions in intra-regional network congestion (Figure 24).

However, some of these components are inherently subject to uncertainty:

- Updated demand forecasts developed for the 2020 ESOO indicate that peak demand in Victoria is less likely to reduce as much as originally assumed in response to energy efficiency initiatives. In this case, Victoria would need over 1 GW or market-based dispatchable resources if Yallourn were to close early (see Appendix 4).
- Market-led VRE development is uncertain, and if developments are not aligned with the ISP's optimal development path or developed ahead of network augmentations, there is risk that some of this VRE will be constrained at critical times.
- Renewables are by nature variable and intermittent and based on historical data they are poorly correlated with peak demand. This means that while Victoria might have a surplus of wind and solar energy at times, during tight demand/supply conditions contributions from renewable sources might be more limited than currently assumed.
- Dispatchable storage uptake, particularly in the form of VPPs, might be slower than expected and feature less controllability than assumed.
- Market-based dispatchable generation more generally, may not be incentivised under current market arrangements to invest. To secure the benefits of all dispatchable resources, market reforms currently being pursued through the ESB's post 2025 market design process need to be continued at pace, otherwise necessary resources may not be delivered on time.

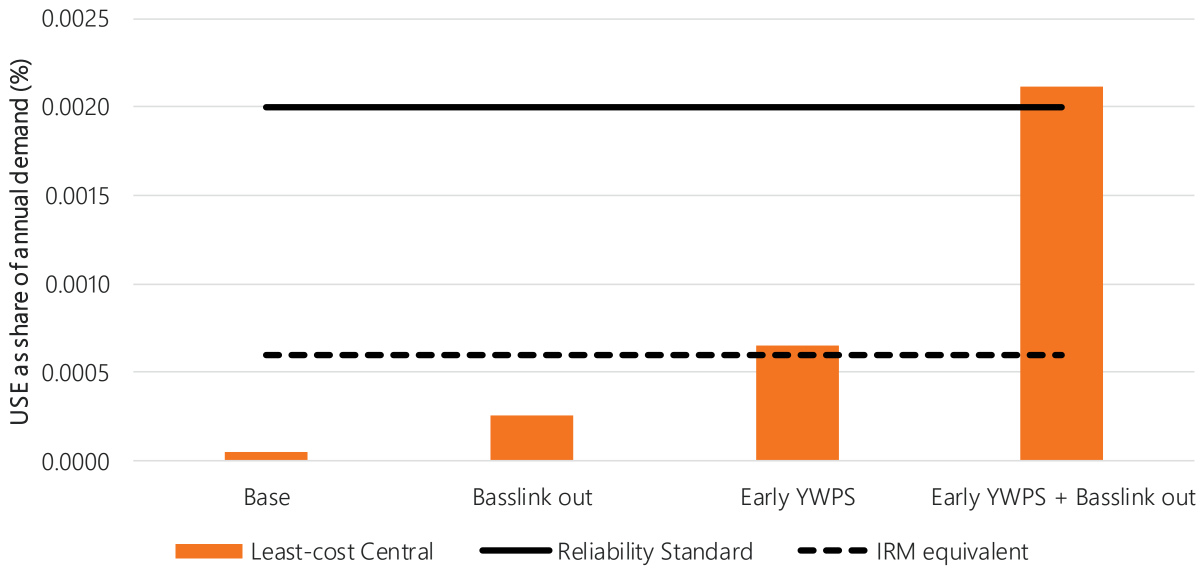
Figure 24 Projected supply sources filling the gap for an early Yallourn retirement in 2027-28



Even if the market responds as hoped, the system is more vulnerable to HILP events once Yallourn retires as the replacement mix of resources are less flexible. Operability analysis shows that if the sort of prolonged generation and transmission outages that occurred in Victoria in the past few years were to reoccur in the future, then supply scarcity risks would be greater for consumers after Yallourn retires.

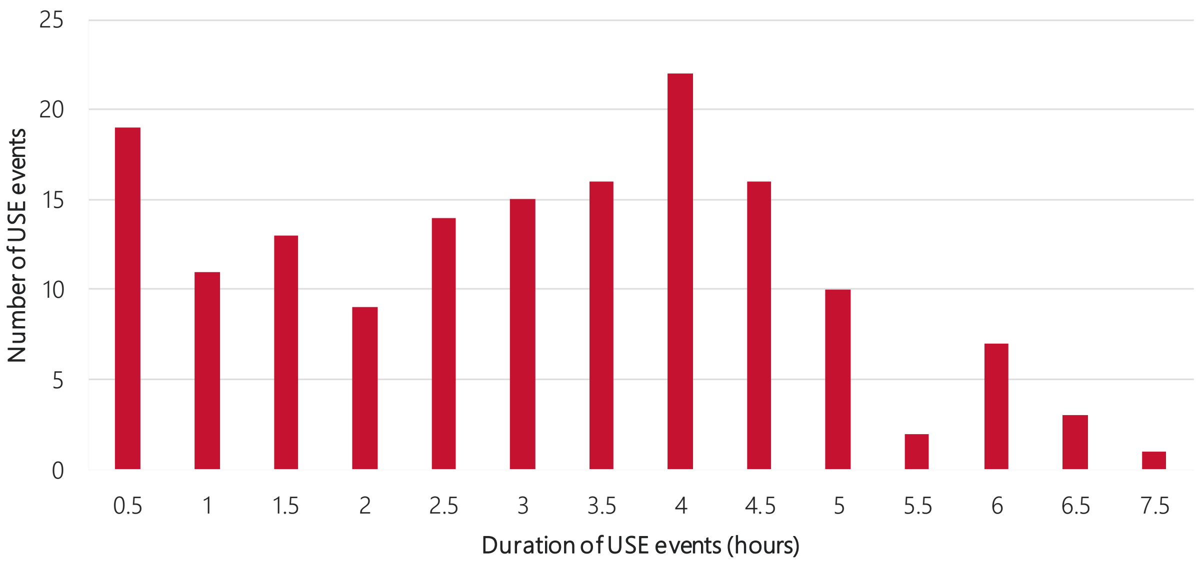
Figure 25 shows the impact on reliability of an extended outage of the Basslink interconnector between Tasmania and Victoria, in the Central scenario, and in the early brown coal closure sensitivity. In both cases (with and without early coal closure) the analysis is based on least cost development path investments in transmission, storage and generation to keep expected USE below the reliability standard. In 2027-28 in the Central scenario, without any prolonged outages ("Base" in Figure 25), the indicative reliability assessment shows that expected USE in Victoria is below both the reliability standard and the IRM equivalent. Even with a prolonged Basslink outage similar to what was observed in 2015-16, the analysis indicates the expected USE would remain within both limits. However, if Yallourn was to retire earlier than currently announced and be unavailable during this year, Victoria's USE would rise to the IRM equivalent. In such a scenario, an unplanned outage on Basslink for up to six months in combination with the early Yallourn retirement would drive USE above the reliability standard.

Figure 25 Victoria projected USE in 2027-28 when stress testing for risks – weighted average across reference years



In the event of a prolonged Basslink outage following a potential early closure of Yallourn, Victoria is also forecast to become susceptible to extended periods of USE, with 66% of the USE events in this year forecast to last more than two hours and 23% of them forecast to be longer than four hours. Such a distribution highlights that shallow storage alone is unlikely to fully mitigate against these USE events due to its limited flexibility.

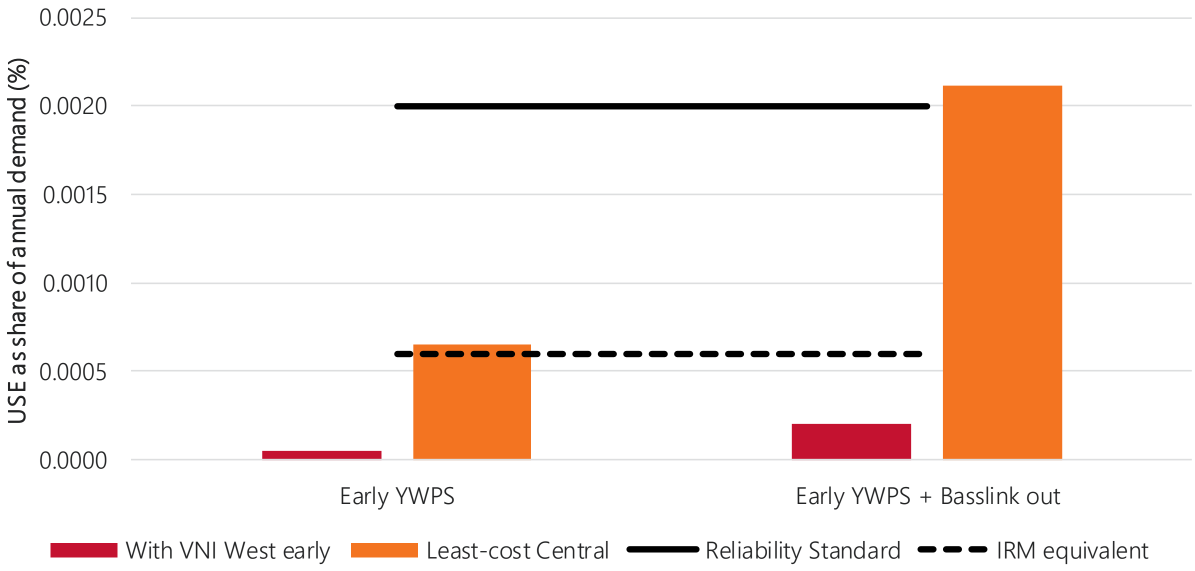
Figure 26 Distribution of USE event duration, early Yallourn retirement and prolonged Basslink outage, 2027-28



Early development of either VNI West route would help mitigate these risks. Figure 27 shows the same projected reliability outcomes for the early Yallourn retirement and Basslink outage scenarios presented in Figure 25, as well as the impacts of an accelerated VNI West being available prior to Yallourn's early retirement (based on DP8, the development path including an accelerated VNI West and early works on

Marinus Link[9]). The additional interconnection between Victoria and New South Wales significantly increases Victoria's resilience to these events without adversely impacting the USE outcomes within New South Wales (not shown).

Figure 27 Resilience of the Victoria system to high impact events in 2027-28, with and without the impact of an early VNI West – (weighted average USE across reference years)



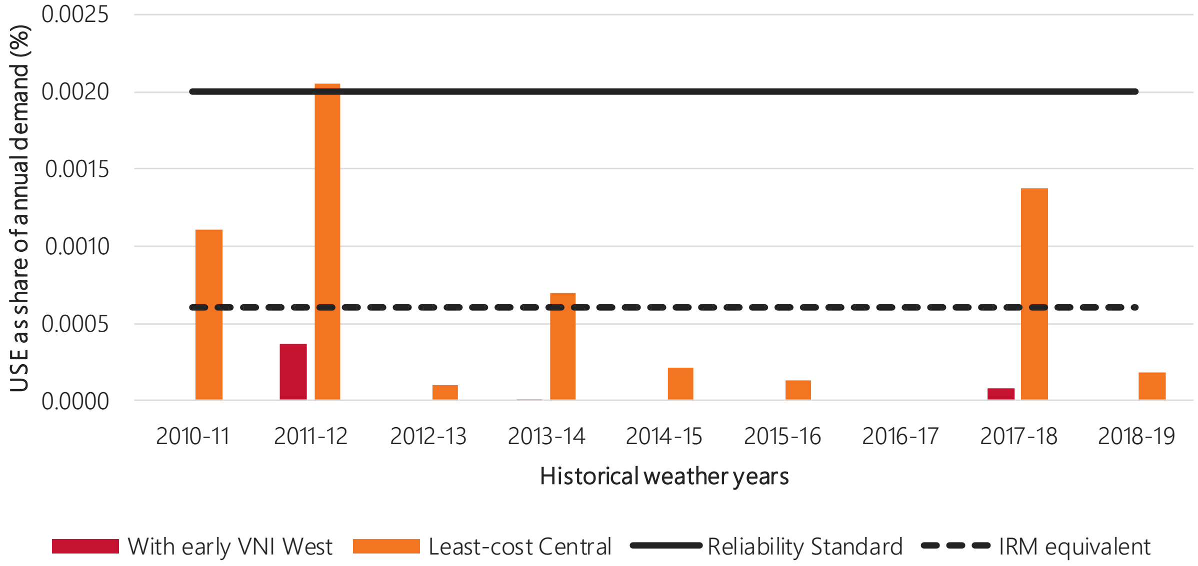
To achieve the same reliability outcomes in the least-cost development path as in the scenario where the early VNI West augmentation takes place, additional investments in firm generation capacity (such as OCGT) would likely to be required. AEMO forecasts that Victoria will require about 1 GW of new capacity to be resilient to HILP events, noting that 1 GW of additional OCGT capacity would cost approximately $705 million (CAPEX only). Early development of VNI West would avoid investments in local generation and boost reliability in the event of a Basslink outage or other high impact event.

In addition to prolonged generation or transmission outages, Victorian consumers are expected to become more vulnerable to supply scarcity risks due to weather-driven events as the penetration of renewable generation increases. Historically, VRE generation has had a relatively weak correlation with peak demand periods. The USE analysis in Figure 28, which is based on the same 2027-28 year as in Figure 25 under the early coal closure sensitivity, shows that annual variations in weather patterns (or reference years) can lead to highly variable USE outcomes in any given year. Peak demand periods coincident with low VRE conditions are expected to be particularly challenging, more so than prior to the Yallourn retirement. While Figure 25 shows the expected USE, averaged across all weather years, is just at the limit of the IRM equivalent in this case, Figure 28 shows that in four of the nine weather years tested, expected USE would be above this limit.

Looking at the same weather patterns and an early Yallourn retirement, combined with the construction of an early VNI West, it is evident that this interconnector augmentation builds system resilience to a broad range of weather events.

[9] See Appendix 2 for more detail regarding the various development paths identified in this ISP.

Figure 28 Victoria USE in 2027-28 with early Yallourn retirement – by reference year



If TRET is legislated (as the Tasmanian government has committed, during 2020), Marinus Link could provide an effective risk mitigant to plant outages, early failures or co-incident 'non-credible' contingencies such as a simultaneous outage of Basslink and a period of low wind production. However, unless cost recovery for the Marinus Link project is resolved, there is no certainty that Marinus Link will be able to proceed. In the event that cost recovery is resolved in a timely manner and Marinus Link is developed, the early development of VNI West would not be regretful as it would serve to help deliver excess VRE from Tasmania through to New South Wales. For further information on the impact and benefits of the TRET and Marinus Link, see Appendix 2).

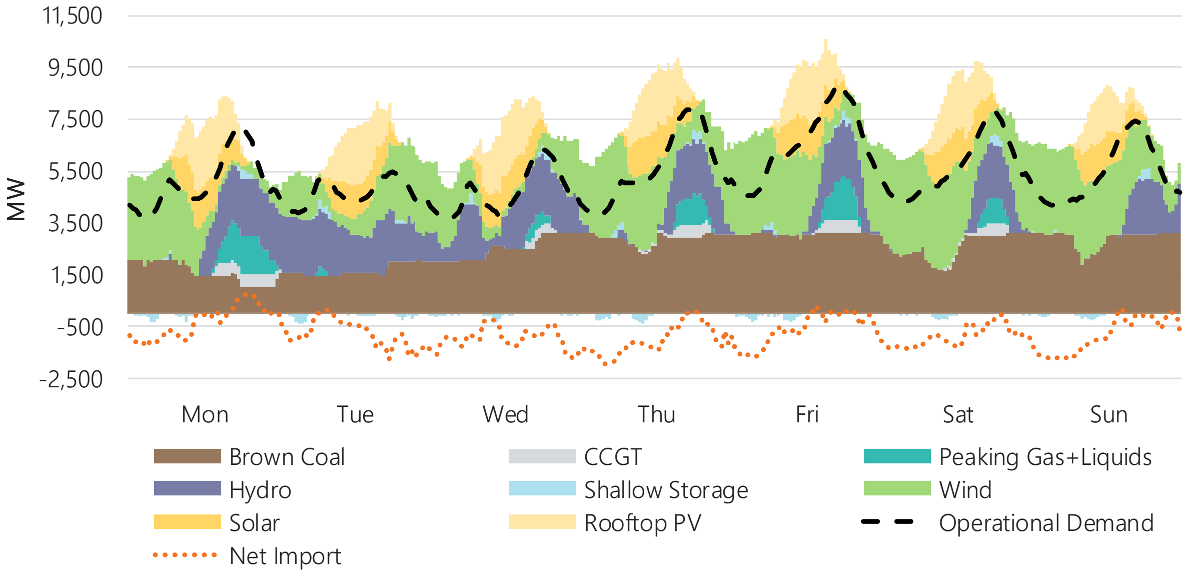
High reliance on local GPG and hydro during challenging times

Without further transmission augmentation Victoria is forecast to be heavily reliant on local GPG and hydro generation during certain time periods. Figure 29 shows projected half-hourly dispatch in a summer week of February 2028, presenting challenges for Victoria due to:

- Major outages (up to 2,000 MW capacity) reducing availability of the thermal fleet.
- Low wind conditions at times.
- Relatively high operational demand.
- Basslink on outage.
- Decrease in brown coal supply due to early retirement.

During this projected sample week, the supply demand balance in Victoria is not particularly tight during the day when local generation, driven by renewables, exceeds local needs and is exported to South Australia and New South Wales. However, during the evening peaks when solar output drops and during calmer wind conditions, Victoria faces some supply scarcity risk. With limited importing capabilities due to Basslink on outage, and without the VNI West development, local gas and hydro generators are required to ramp heavily, with DSP and VPP being the other two key sources of flexibility and support during these times. Hydro generation is also relied on during low wind periods, which can extend for several hours or days.

Figure 29 Victoria in February 2028, projected dispatch



With GPG forecast to play such an important role in a future without increased transmission, considerations on affordability and gas supply availability become critical. There might also be restrictions to when and to what extent hydro resources are available that could require gas to play an even larger role in the future energy mix. In this regard, an early VNI West would allow Victoria to access more dispatchable resources – including the storage depth of Snowy 2.0 from New South Wales – that could increase resilience during these challenging times.

Lower competition and impact on affordability

Although Victoria is forecast to continue exporting heavily to New South Wales, during tight supply/demand conditions lack of further transmission upgrades increases the risks of scarcity pricing. Affordability concerns arise in the context of HILP events (such as loss of Basslink) as well as early coal retirement (planned our unplanned) which would naturally increase reliance on local generation.

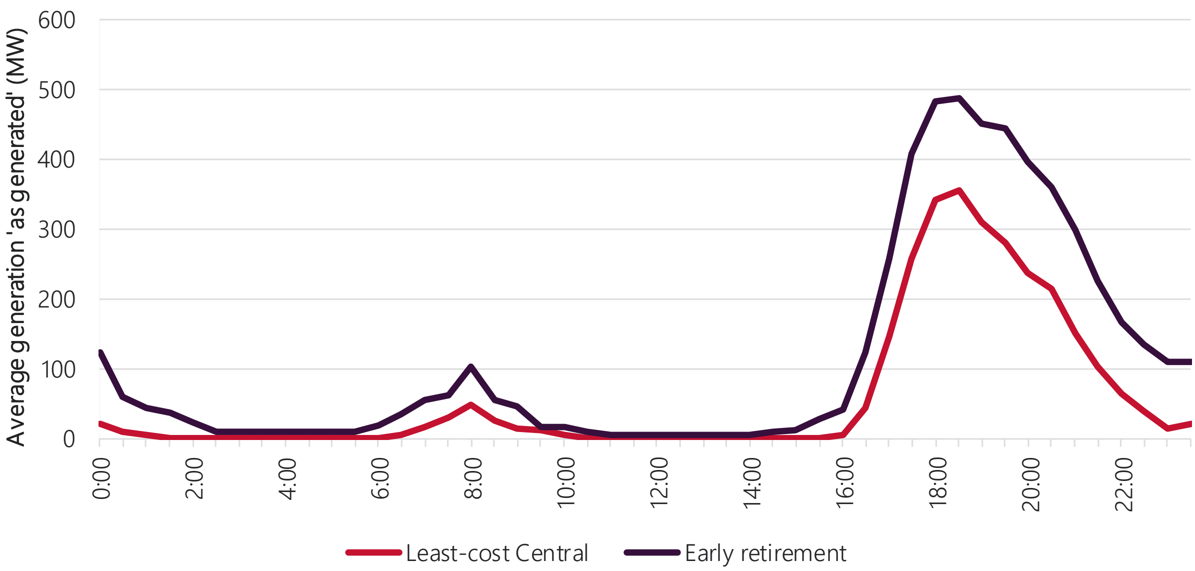
AEMO's bidding model indicates that in 2027-28 wholesale prices in Victoria will become more volatile and increase in 70% of the periods should a retirement occur earlier than expected. This shift upwards might expose consumers to higher costs (Figure 30).

Figure 30 Estimated wholesale price duration curve in Victoria in 2027-28

With an earlier than expected reduction in brown coal supply, AEMO forecasts that existing GPG will became the marginal source of generation more frequently. In the absence of additional competition from imports, during shoulder months featuring low VRE and/or periods where coal generation is not available due to maintenance, opportunities for GPG to set the price will increase (Figure 31).

With VNI West in place, Victoria has access to an additional 1.2 GW import capacity to access lower-cost resources across the NEM and reduce reliance on local GPG, particularly OCGTs, which could be displaced by more cost-efficient sources (typically black coal). VNI West therefore strengthens wholesale market competition and may help to mitigate risk of scarcity pricing for Victorian consumers. The impact on wholesale electricity prices, and ultimately consumer bills will depend on the extent to which generators move towards more cost reflective pricing in response.

Figure 31 Projected average time-of-day gas generation in Victoria in June 2028 with and without early coal retirement



Other risks

Brown coal operating regimes

As discussed in Section A6.3.3, traditional brown coal operating regimes may be challenged in a power system dominated by low-cost renewable generation.

Early development of VNI West provides for increased export capability that may soften requirements for flexible operation of brown coal generation.

A6.4.4 South Australia

Key messages

- From a system operation perspective, maintaining an adequate level of system strength, inertia, operating reserves and frequency control will continue to be a critical challenge in South Australia.
- Project EnergyConnect allows the minimum requirement of synchronous generating units online to be reduced and thus deliver significant savings in overall system fuel costs.
- While system security requirements are not a key driver of GPG post-delivery of Project EnergyConnect, GPG is expected to continue playing a key role during periods of low renewable availability. From the early 2030s storage becomes critical to meet steeper ramping requirements in the evening and morning peak.
- Without Project EnergyConnect, South Australia is forecast to continue relying on local synchronous generators for the foreseeable future. In this scenario retirement of existing GPG is a key concern for the security and reliability outlook of South Australia. Without further interconnection, investments in new synchronous generation capacity will be required in response to Osborne withdrawal as well as when Pelican Point retires in the mid-2030s.

From a system operation perspective, maintaining an adequate level of system strength, inertia, operating reserves and frequency control will continue to be a critical challenge in South Australia. At present, a minimum local commitment of large synchronous generating units is needed in South Australia to provide essential power system services.

This will be partially addressed by high-inertia synchronous condensers from 2021, however South Australia is still forecast to be required to maintain a minimum number of synchronous generating units online at all times until an additional interconnector is commissioned (e.g. Project EnergyConnect). For more information on these issues, refer to Appendix 7, Future Power System Security.

Figure 32 shows projected average time-of-day generation in South Australia pre (2023-24) and post (2024-25) Project EnergyConnect. Prior to Project EnergyConnect being operational, the impact of keeping two synchronous generators online at all times can be clearly seen. While demand is largely met by renewable energy, due to operational requirements, South Australia continues to rely heavily on local GPG throughout the day with flexible technologies (including storage) to provide additional support for the morning and evening peak.

With assumed delivery of Project EnergyConnect in 2024-25, operational requirements on local generation are expected to be lifted and reliance on gas is forecast to drop, particularly during the day, and be replaced by greater imports from New South Wales and Victoria.

Figure 32 Average time-of-day generation in South Australia in 2023-24 (left) and 2024-25 (right), Central scenario

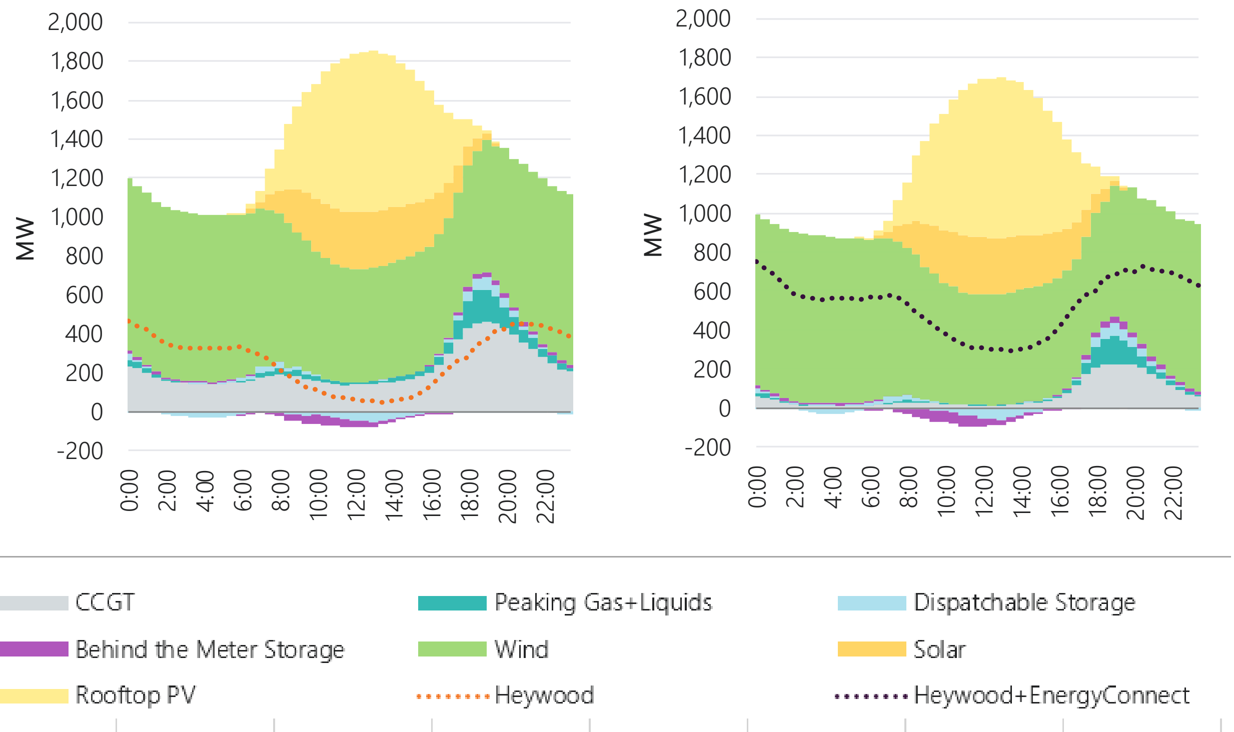
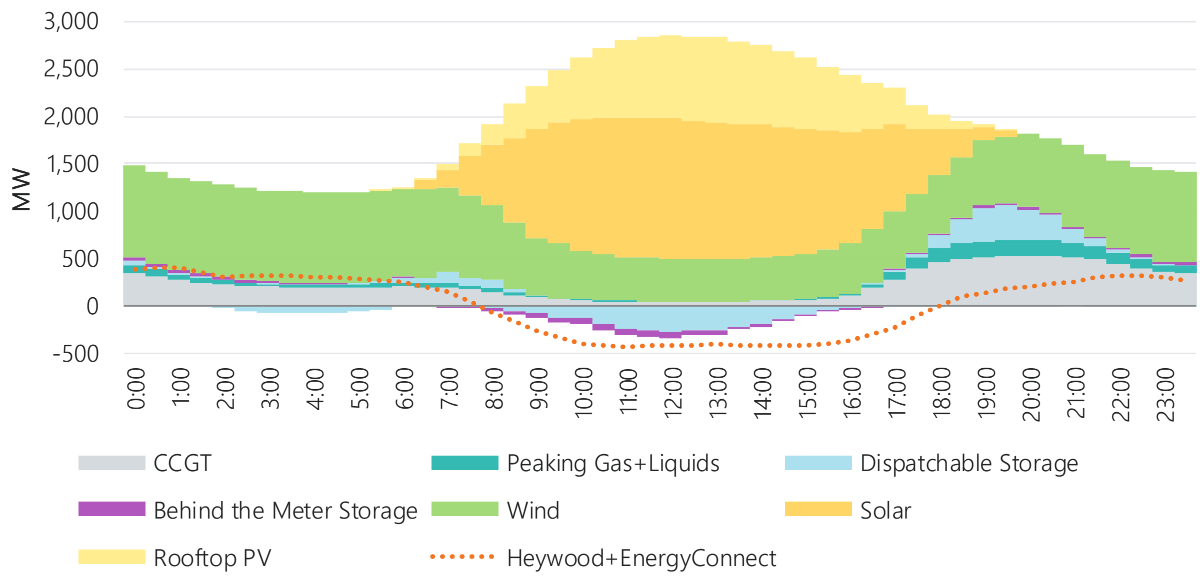


Figure 33 presents average time-of-day generation in South Australia in 2034-35 where excess solar output is exported to Victoria and New South Wales. While system security requirements are not a driver of GPG in 2035, GPG (particularly from CCGTs) is expected to continue playing a key role during periods of low renewable availability. Ramping between midday (when renewable energy exceeds regional demand on most days) and evening is typically 2.4 GW but can be up to 4 GW. This ramping requirement is met by a combination of GPG, storage and imports.

Figure 33 Average time-of-day generation in South Australia in 2034-35, Central scenario



Fast start technologies, such as shallow storage, are expected to play a critical role in supporting conventional peaking generation to meet demand during periods of low VRE generation. By 2034-35 the least-cost development path projects new installed capacity of shallow storage will reach 582 MW and progressively increase to 1,144 MW by the end of the study period. These shallow storages supply reliable and continuous generation over short timeframes (of up to 2 hours), yet during prolonged windows of tight supply-demand balance, existing gas generators are forecast to continue to play an important part in the supply mix of South Australia. Uptake of deeper storage is not projected until retirement of Pelican Point after which 4-hour storage will become more valuable to replace firm capacity, with 860 MW of new medium storage forecast to be installed in South Australia by 2041-42.

See Appendix 5 for an assessment of the South Australian REZ development.

The technology mix in South Australia in the Central scenario counterfactual

With the anticipated retirement of synchronous generation in South Australia, a suite of technology solutions will be required to address energy, capacity and security requirements.

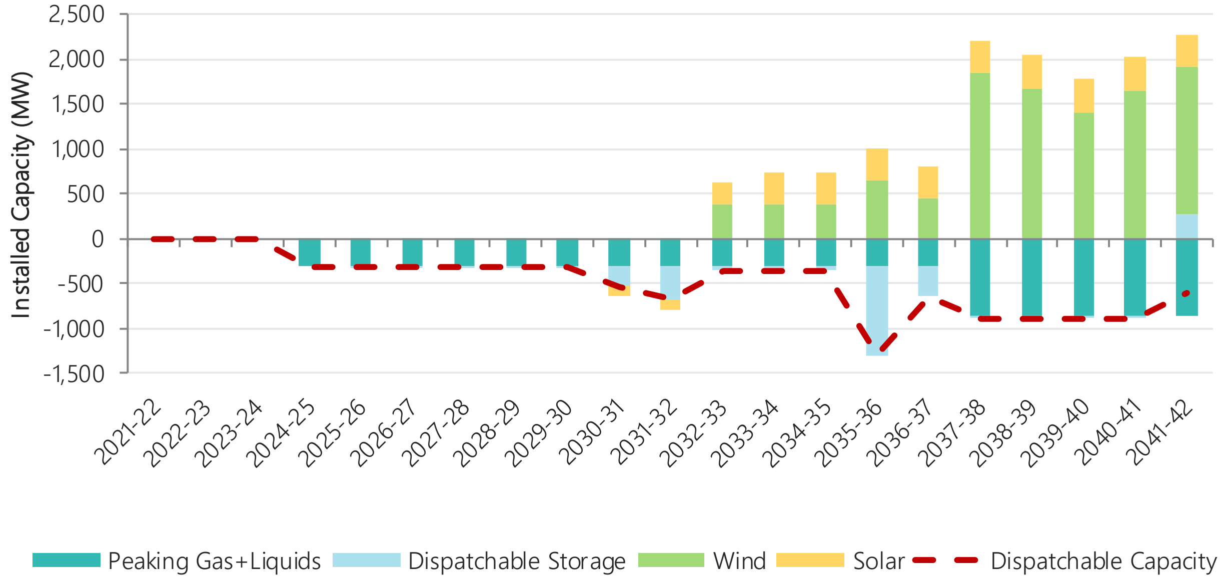
Retirement of existing GPG is a key concern for the security and reliability outlook of South Australia. Following Osborne and Torrens Island A announced retirements, and without further interconnection, investments in new synchronous generation capacity will be required as early as 2024-25.

Between the late 2020s and early 2030s some existing wind capacity is also expected to withdraw from the market, thus increasing the risk of a local supply shortage should no new investments in local generation and/or transmission materialise.

With retirement of Torrens Island B (2035-36) followed by Pelican Point (2037-38) alternative sources of firm capacity are again forecast to be required to maintain system security in the Central scenario counterfactual.

0 shows a comparison of the capacity built in the Central scenario least-cost development path compared to the counterfactual.

Figure 34 Comparison of capacity built within South Australia in the least-cost development path (top) and counterfactual (bottom)



Without further transmission:

- South Australia is forecast to require additional investments in local OCGT generation as a response to Osborne retiring in 2023-24, with additional peaking capacity needed following the retirement of Pelican Point in 2037-28.

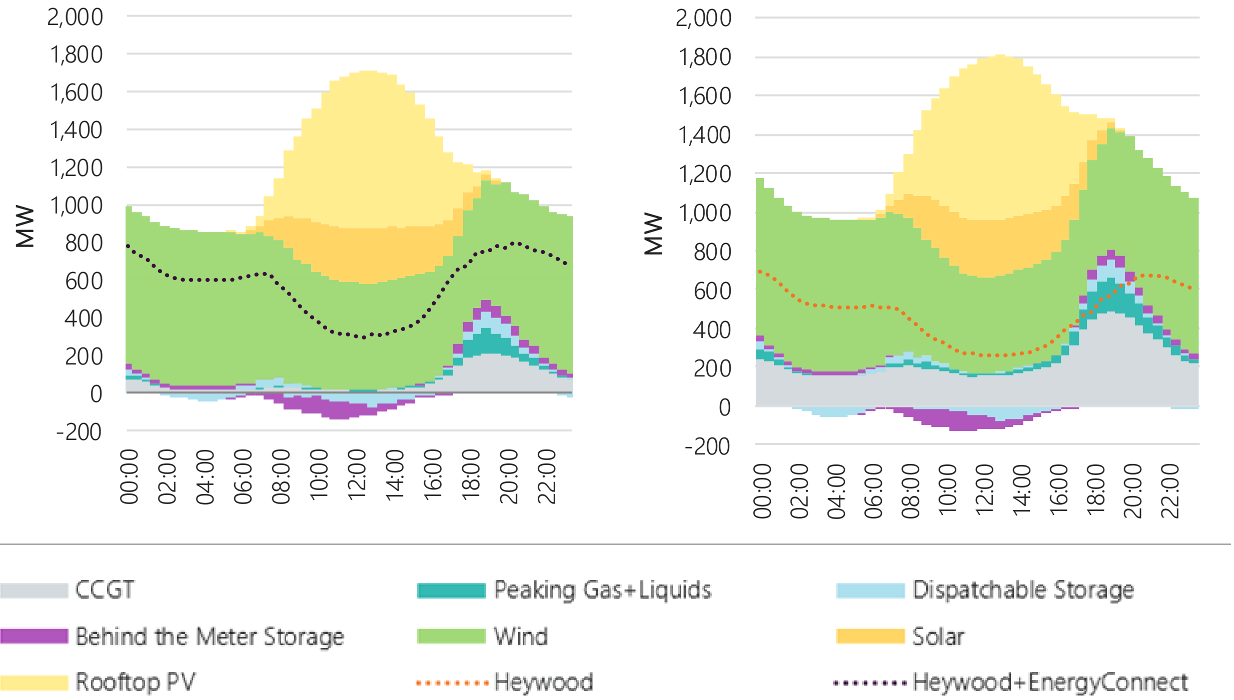
- Additional and earlier investments in dispatchable storage are required to ensure system reliability.
- Less VRE is forecast to be built within South Australia, as the ability to share with neighbouring states is reduced.

Figure 35 compares projected average time-of-day operation of South Australia in 2029-30 under the Central scenario least-cost development path compared to counterfactual. Without transmission development, GPG generates continuously throughout the day and – due to South Australia's limited ability to import at peak – additional support from GPG is forecast to be required, above and beyond system security requirements.

Estimated reliability risks

As described in Section A6.3.1, there are no indications of reliability risks for South Australia across the forecast period, except for the year when Osborne Power Station retires in 2023-24. USE in South Australia under Central scenario in 2023-24 is slightly above the IRM limit but does not include any contribution from South Australian diesel generation currently in the process of being leased to participants. Inclusion of this capacity would be likely to bring the USE below 0.0006%.

Figure 35 Average time-of-day operation of South Australia in 2029-30 in the Central least-cost development path (left) and counterfactual (right)



A6.4.5 Tasmania

Key messages

- Variation in rainfall inflows into hydro reservoirs is closely correlated to the amount of energy Tasmania exports to the mainland on an annual basis. At times of heavy rainfall, greater interconnection allows for better utilisation of the available water at times when it is most needed on the mainland. At times of lighter rainfall, interconnection provides alternative energy supply options.
- If the TRET policy is legislated and Marinus Link is built, then it is forecast that by 2034-35 Tasmania would be a net exporter of energy in most time periods (80% of the time), while importing excess solar generation from the mainland in the remaining time periods (20% of the time).

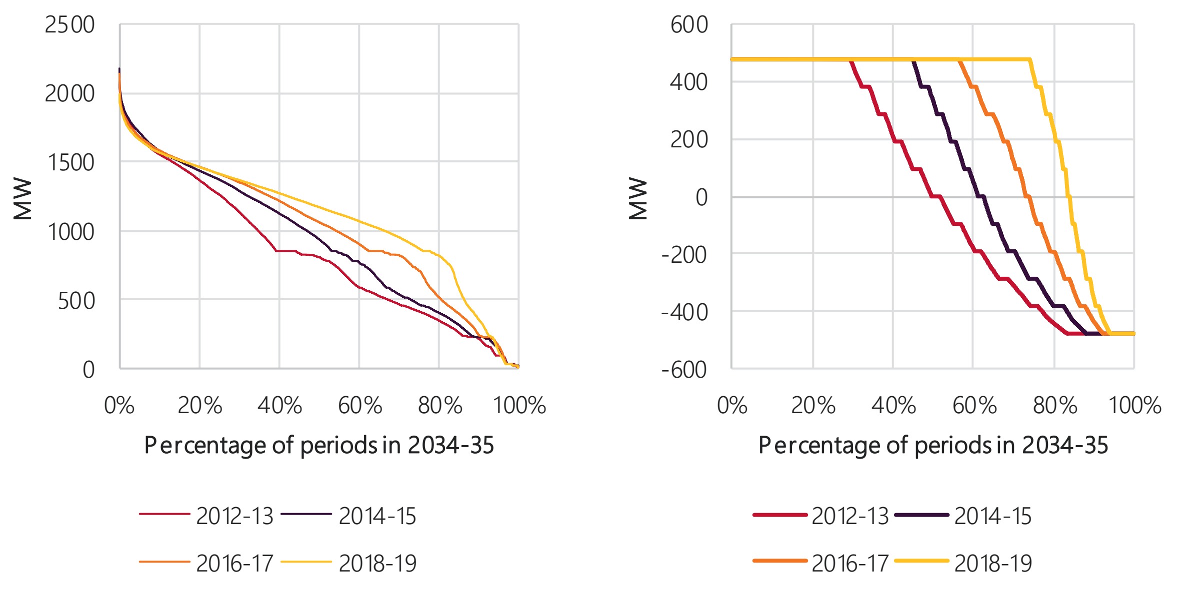
The announced potential for expansion of the TRET of 100% VRE by 2021-22 to 200% VRE by 2039-40 results in a material increase in VRE production in this region. The policy has been implemented in AEMO's modelling as a linear increase of variable renewable energy, including distributed PV and small non-scheduled renewable generation, to double the current output by 2040 (and target 150% by 2030). To meet the 200% TRET, compared to the Central scenario least-cost development path, approximately 1,390 MW of additional renewable generation capacity in Tasmania is forecast to be required by 2040. In total, 2,600 MW of additional VRE is assumed to be developed in the region in response to the RET, in addition to existing, committed, and anticipated renewable energy projects[10]. An assessment on the development of Tasmanian REZ can be found in Appendix 5.

This additional renewable capacity would require either a new transmission development or local consumption response (or both) to avoid excessive VRE spill. The new transmission development, that is, Marinus Link, could export the excess of renewable energy to the mainland. Without Marinus Link, Tasmanian electricity demand will need to increase to ensure the additional renewable energy is fully utilised. This local consumption response could potentially consider a range of industrial or commercial initiatives, including hydrogen-based facilities. For more discussion of hydrogen potential in Australia, see Appendix 10.

Hydro generation in Tasmania varies by each reference year that is applied within the forecast, not only in response to wind and solar variability, but also because the amount of rainfall in a given reference year has a considerable effect on hydro inflows and subsequent generation.

Figure 36 shows there is a relationship between the forecast distribution of hydro generation and the forecast distribution of Basslink flows. Hydro generation is forecast to be a driver of the variation in exports across reference years (noting that it is a model assumption that all reservoirs do not store excess rainfall from one year to use in drier years). For example, the 2012-2013 reference year represents a drier period and the 2018-2019 reference year represents a wetter period. Tasmania is an exporter (Basslink flows positive) in 50% of periods in reference year 2012-13, compared to over 80% of periods in reference year 2018-19, corresponding to higher hydro generation in 2018-19 than in 2012-13.

Figure 36 Tasmanian hydro generation duration curve by reference year (left) and Basslink flow duration curve by reference year (right), Central scenario, 2034-35



[10] Details on these projects can be found in the ISP Input and Assumptions Workbook, available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines

In a future where more renewable capacity is built in Tasmania, variability of interconnector flows under different weather conditions becomes more pronounced, and the role of interconnection becomes more critical. Some of this energy could be managed by the large interannual storages such as Lake Gordon and Great Lake, although this is not captured in the model.

Central development path with TRET and accelerated Marinus Link

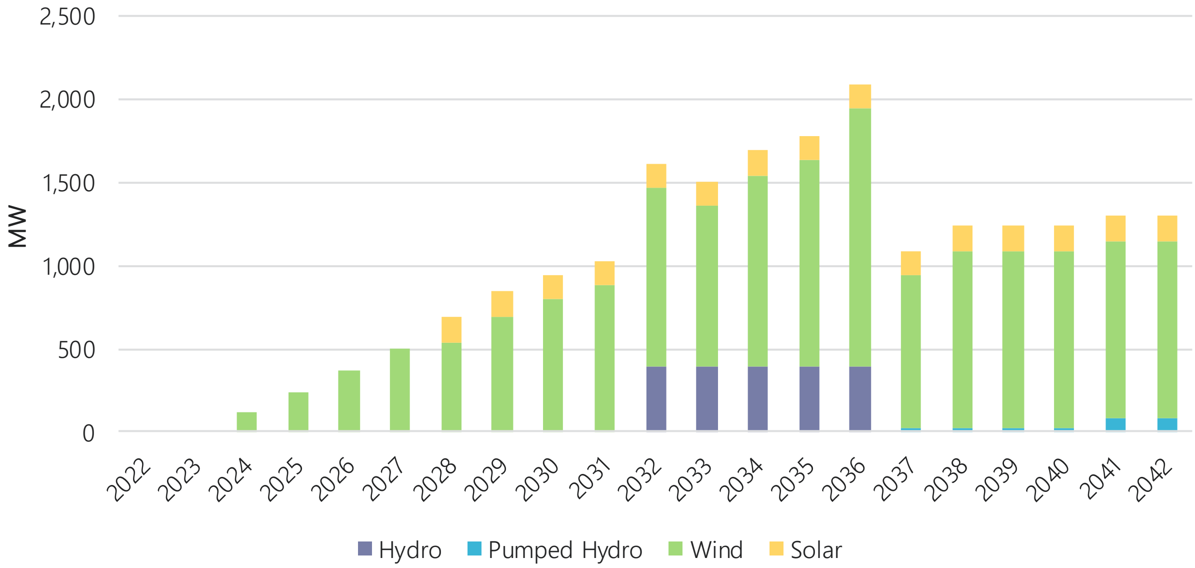
While the most cost-effective outcome for the Central scenario least-cost development path forecasts that Marinus Link (Stage 1) should be constructed by 2036-37, should TRET progress, the least cost development path brings Marinus Link forward to 2031-32.

A Central development path, that includes TRET and brings forward the timing of Marinus Link to 2031-32, is compared with the Central scenario least-cost development path (without TRET and with Marinus Link operational from 2036-37). The additional installed capacity in Tasmania with TRET and Marinus Link accelerated can be seen in Figure 37.

With the TRET policy enforced and Marinus Link timing brought forward, an additional 1.1 GW of wind capacity and 0.2 GW of solar capacity is built in Tasmania by 2041-42 compared with the Central scenario. Some additional pumped hydro storage is developed in the later years with TRET.

Tasmanian hydropower capacity upgrades associated with maintenance, refurbishments and system optimisation are all assumed to be coordinated with Marinus Link commissioning and are therefore brought forward with the earlier timeline[11] (not shown in Figure 37).

Figure 37 Additional installed capacity in Tasmania with TRET and Marinus Link accelerated to 2031-32 relative to Central scenario least-cost development path



In 2034-35, without TRET and Marinus Link, Figure 38 shows that Tasmania is on average a net importer during the middle of the day, where ample low cost solar from the mainland is prioritised, saving the higher cost Tasmanian hydro for less plentiful times. In the evening hours, Tasmania becomes a net exporter as Tasmanian hydro operation displaces some amount of mainland gas and coal during the evening ramp period and overnight.

With TRET and Marinus Link, Figure 39 shows that by 2034-35 Tasmania is (on average) a net exporter for most of the day. There are 4-6 hours in the middle of the day where the average exports cease in response to

[11] For more information, refer to https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/unlocking-tasmania's-energy-capacity_december-2018.pdf?sfvrsn=8d159828_6.

ample mainland solar availability, outside of this window wind and hydro generation is exported to the mainland.

Figure 38 Tasmania average time-of-day generation without Marinus Link and without TRET, 2034-35, Central scenario, reference year 2013

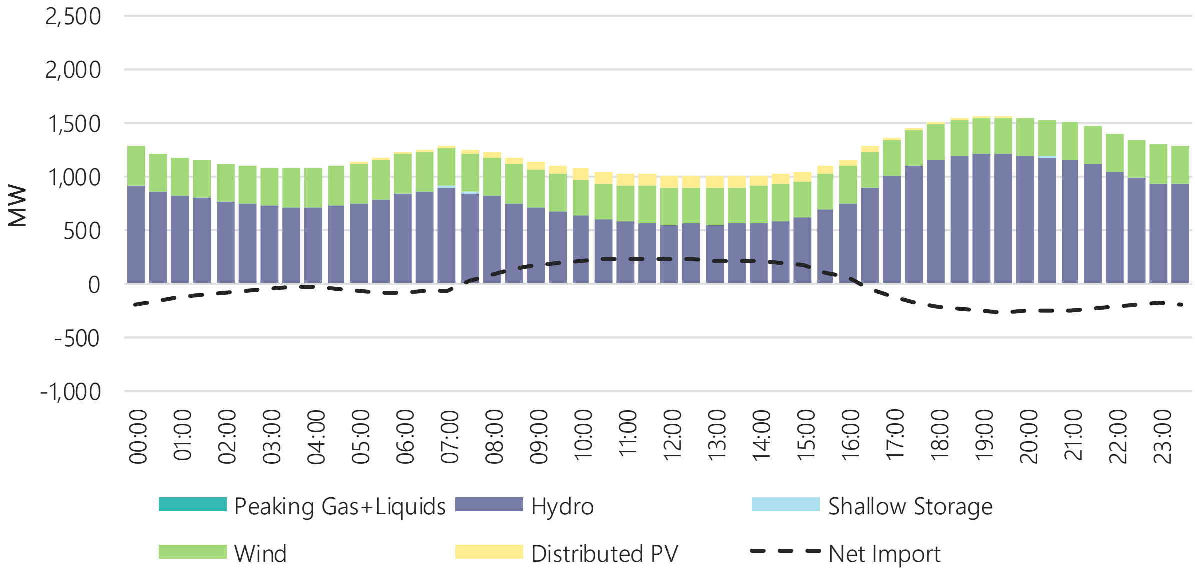
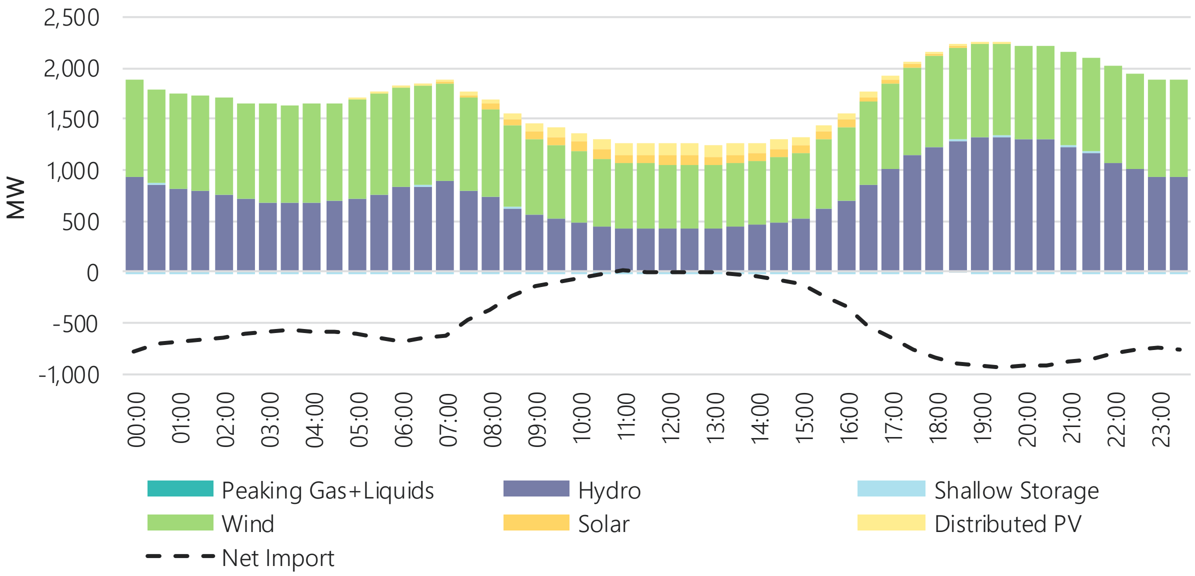


Figure 39 Tasmania average time-of-day generation with Marinus Link and TRET, 2034-35, Central scenario, reference year 2013



Even if the timing of Marinus Link is brought forward, if TRET is legislated, spill from VRE (large-scale wind and solar) is forecast to be as high as 19% in some months of the year by 2034-35. This indicates that exports to the mainland via Marinus Link Stage 1 are not sufficient to make full use of the additional VRE capacity installed to meet TRET. While the value of avoiding this spill is not sufficient to justify bringing forward Marinus Link Stage 2, this could be addressed by introducing more storage, or increasing local demand – such as the development of a hydrogen industry – to take advantage of the curtailed VRE.

Without TRET, the capacity expansion model limits VRE build, resulting in VRE spill in Tasmania well under 1% on average.

Figure 40 VRE spilled as percentage of available capacity, Tasmania, Central scenario, without TRET compared to with TRET and accelerated Marinus Link

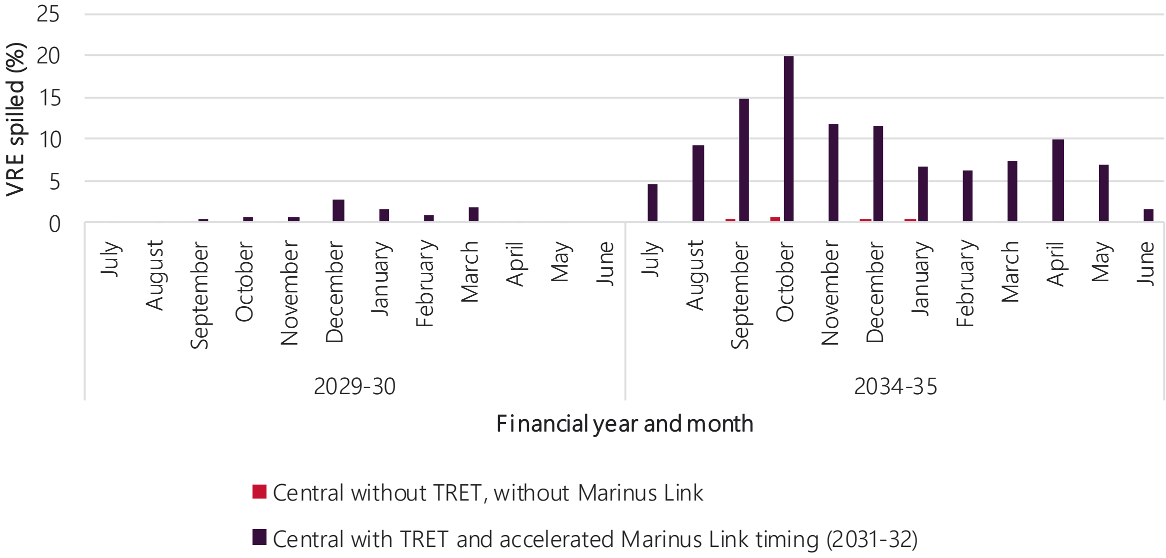
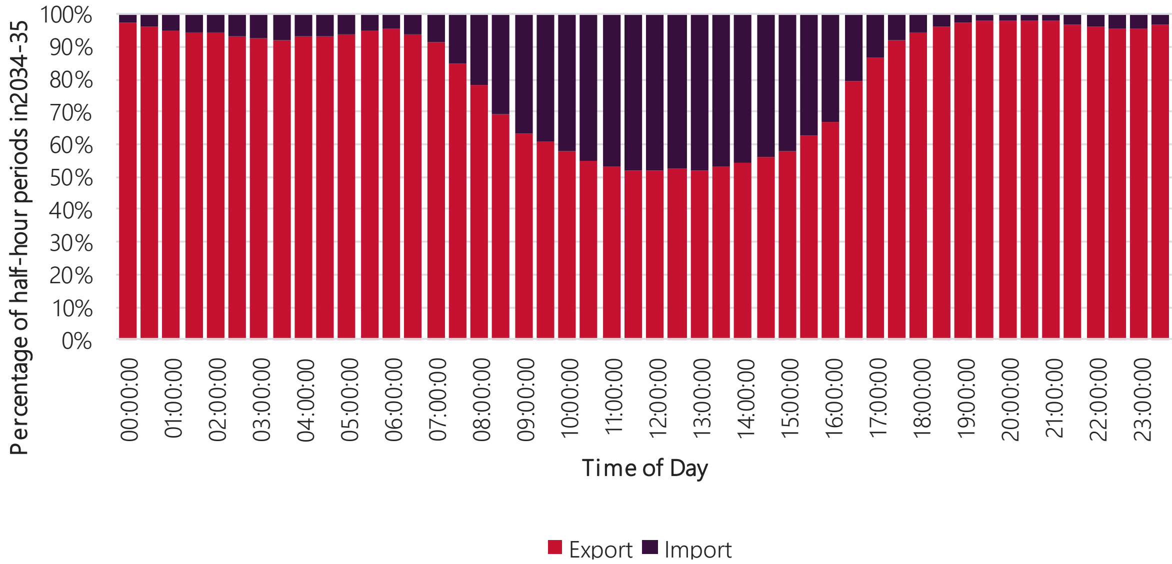


Figure 41 shows Tasmania's exports and imports in 2034-35, varying across the time of day, taking into account flows along both Basslink and Marinus Link. This shows that Tasmania is forecast to be a net exporter 80% of the time and a net importer 20% of the time, with Tasmania importing mainland solar generation during the middle of the day when solar availability is high. Marinus Link not only enables the mainland to access Tasmanian wind and hydro, but also enables Tasmania to access mainland solar. As already discussed, importing mainland solar during the middle of the day allows the Tasmanian hydro generation to be stored and deferred for generation at another time.

Figure 41 Percentage of periods that Tasmania exports and imports by time-of-day, 2034-35, Central scenario with TRET and accelerated Marinus Link, all reference years

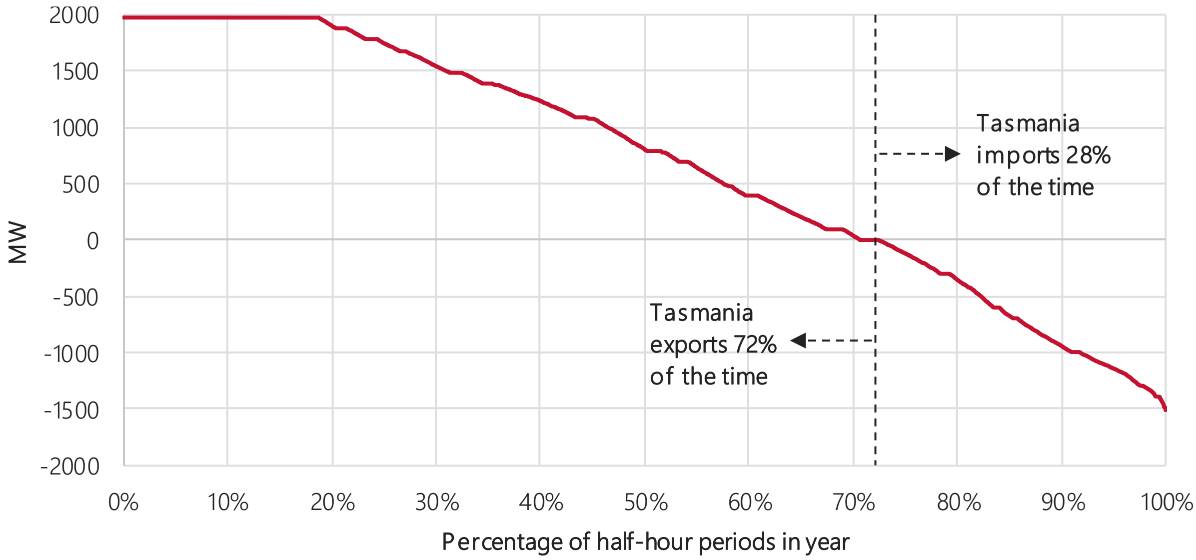


As mentioned in Appendix 4, bringing forward Marinus Link allows TRET energy exports to the mainland earlier, with increased flows sent to New South Wales when the VNI West augmentation is developed. This highlights the importance of greater interconnection across the NEM as a means for realising the full value of VRE generation development that is driven by state-based renewable policies.

Step Change development path with TRET and Marinus Link

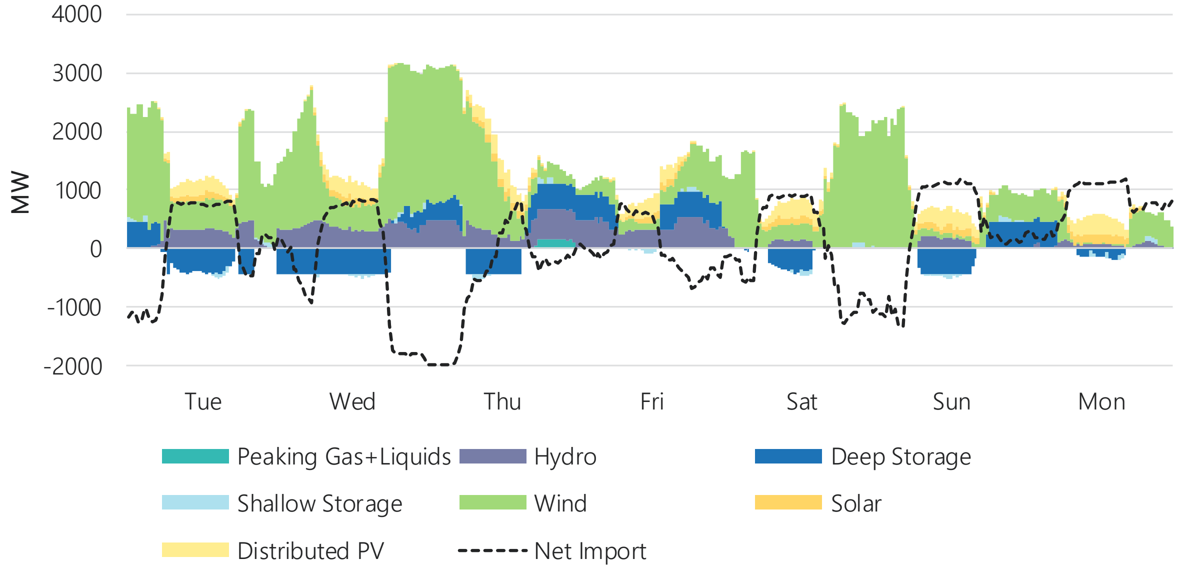
By 2039-40, over 350 MW of deep pumped hydro capacity is forecasted to be required in Tasmania under the Step Change least-cost development path. When combined with Marinus Link's 1,500 MW of additional interconnection capacity, Tasmania has the ability to import mainland solar during daytime hours to fill pumped hydro reservoirs or defer hydro generation, and export to the mainland during the evening and night. Figure 42 below indicates that Tasmania is forecast to import from the mainland in 28% of periods, (more often than in the Central scenario) and these periods are, again, overwhelmingly during the hours of high solar availability between 8am and 4pm.

Figure 42 Combined Bass Link and Marinus Link flow duration curve, 2039-40, Step Change with TRET and Marinus Link, reference year 2012-13



An example of interconnector flows and pumped hydro dispatch being operated in tandem is shown in Figure 43, where Tasmania imports during the daytime as deep storages pump, sometimes for consecutive days, and exports during the evening and overnight as storages discharge, or wind generation is high.

Figure 43 Dispatch profile in Tasmania for a week in December 2039-40, Step Change with TRET and Marinus Link, reference year 2012-13



While storages charging and discharging do not account for the entirety of the imports and exports, the concurrence of imports with charging and exports with discharging suggests that Tasmania can play an important role as a store of mainland renewable generation.

Estimated reliability risks

As described in Section A6.3.1, there are no indications of reliability risks in Tasmania across the forecast window.