AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

2018 Electricity Statement of Opportunities

August 2018

A report for the National Electricity Market

Important notice

PURPOSE

AEMO publishes the National Electricity Market Electricity Statement of Opportunities under clause 3.13.3(q) of the National Electricity Rules.

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VERSION CONTROL

Version	Release date	Changes
1	24/8/2018	Initial release

Executive summary

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period to inform the decision-making processes of market participants, new investors, and policy-makers as they assess future development opportunities.

In 2018, AEMO's ESOO modelling continues to show a heightened risk of unserved energy (USE)[1] over the next 10 years, confirming again that additional investment will be required in a portfolio of resources to replace retiring capacity, and that, for peak summer periods, targeted actions to provide additional firming capability are necessary to reduce risks of supply interruptions.

For summer 2018-19, AEMO is working closely with industry and government to manage projected risks at times of summer peak demand:

- In consultation with the Victorian Government, AEMO is seeking to contract additional reserves under the Reliability and Emergency Reserve Trader (RERT) mechanism, to manage the projected risk in Victoria of the reliability standard[2] not being met, and of loss of consumer load.
- The forecast risk of load shedding in 2018-19 has increased since the 2017 ESOO, primarily because modelling has now factored in a reduction in thermal generation reliability observed in recent years.

After this summer, the level of risk is forecast to reduce through to 2020-21, as more resources continue to be installed:

- Modelling includes over 5.6 gigawatts (GW) of committed[3] new generation and storage capacity, and upgrades to existing generation. Most of this has become committed since the 2017 ESOO, with some 2.7 GW of utility-scale wind and solar generation added in the past quarter alone, mainly in Victoria.

In the medium to longer term, investment in resources beyond those that are currently committed will be required to maintain reliability within the standard in Victoria, New South Wales, and South Australia:

- After the announced retirements of the Torrens Island A Power Station (480 megawatts [MW], between 2019 and 2021) and Liddell Power Station (1,800 MW, in 2022), the level of USE is projected to increase significantly without further NEM development.
- The results emphasise the need for an investment landscape which supports the development of the portfolio of resources required to replace retiring generation.
- AEMO will continue to work with state governments in affected regions to help ensure local reliability requirements are met.
- As AEMO outlined in the 2018 *Integrated System Plan* (ISP), system reliability requires that new utility-scale renewable generation be complemented by storage, distributed energy resources (DER), flexible thermal capacity, and transmission, to ensure dispatchability in all hours.

[1] Unserved energy (USE) is energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply), as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand.

[2] The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year

[3] AEMO's commitment criteria for generation are published under the Background information tab in each regional spreadsheet on its Generation Information web page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Reliability assessments

To forecast reliability of supply for the NEM in this 2018 ESOO, AEMO has:

- Developed new demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in consumer behaviour. The forecasts for operational (from the grid) demand account for forecast growth in distributed rooftop photovoltaic (PV) generation and storage.
- Updated data on the supply available to meet this demand, to include the latest information on generation in the NEM which is connected to or is committed to connect to the grid.
- Reviewed the performance of existing conventional generation and refined the modelling of its performance to better reflect recent operating experience.
- Made some allowance for uncertainty in the transfer capability of the major interconnectors, reflecting their importance in delivering reliable supply to consumers.
- Run multiple simulations of future dispatch outcomes to determine the probability of any shortfalls, which are expressed in terms of the forecast USE and compared to the NEM reliability standard.
- Computed a range of other measures to provide a broader picture of the risk to reliable supply.

Forecasts have also been developed for the Slow change and Fast change scenarios outlined in the 2018 ISP, acknowledging the scope for considerable uncertainty in outcomes.

The ESOO traditionally models the ability of only existing and committed generation to meet forecast demand. This provides an important input to AEMO's operational planning for summer readiness[4], because further market investment, above what is already committed, is unlikely to be available in the short term. However, investment is possible with sufficient lead time. In the medium to longer term, the ESOO highlights opportunities for market investment to meet consumer needs, and the risks if investment is not forthcoming.

Demand forecasts

The demand forecasts produced for this 2018 NEM ESOO reflect the latest outlook on economic drivers, population growth, and connection numbers, energy efficiency, electric vehicles, rooftop PV, and residential and small business energy storage systems.

Underlying consumption is expected to continue to increase as the economy and population grow:

- Consumption in the manufacturing sector is expected to gradually recover as economic conditions continue to improve, but is not projected to return to historical levels within the forecast period.
- The non-energy-intensive business sectors (predominantly retail and services) are forecast to grow steadily, in line with increases in population and consumer confidence. This growing sector makes up the largest component of business sector consumption in aggregate and dominates the overall trend.
- Households are using electric appliances, such as home entertainment appliances and space conditioning, more than ever, and this trend is forecast to continue, although consumption per household is expected to remain relatively flat due to energy efficiency improvements.
- More household connections are forecast, with recent construction trends in new dwellings in capital cities driving the growth over the next five years.
- Electrification of transport is projected by CSIRO[5] to further increase consumption from 2030, when electric vehicles are forecast to become cost-competitive with other transport alternatives.

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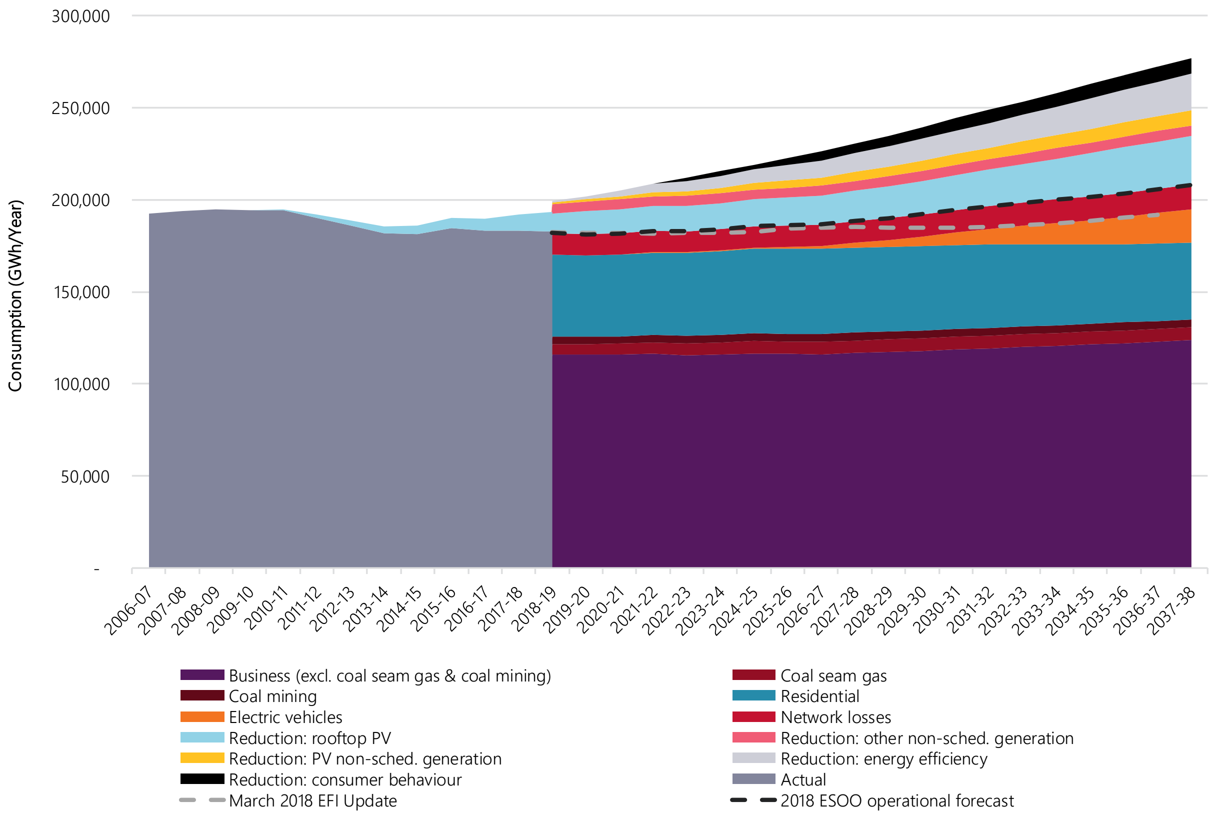
[4] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report.

[5] Graham, P., Wang, D., Braslavsky, J., and Reedman, L. (2018). *Projections for small-scale embedded technologies*. CSIRO report prepared for AEMO, published as supplementary material to the 2018 ESOO.

Figure 1 NEM electricity consumption, actual and forecast, 2006-07 to 2037-38, Neutral scenario



Despite this projected growth in underlying consumption, the consumption of NEM grid-supplied energy over the next 10 years is forecast to remain flat, due to continued improvement in energy efficiency and growth in rooftop PV and non-scheduled generation. Until 2028, operational consumption forecasts remain relatively unchanged since last year. In the second half of the outlook period, grid demand grows and grows faster than previous forecasts based on expected growth in electric vehicles, as shown in Figure 1.

In the past year, rooftop PV installations have grown by 20% in the residential sector and almost 60% in the business sector. High growth is forecast to continue for the next three years, at a rate about 30% faster than what was previously projected over the same period[6], before plateauing through the next decade.

This uptake of rooftop PV continues to shift maximum operational demand to later in the day, at times when the contribution of rooftop PV is declining. Within the next decade, maximum operational demand in most regions is expected to reach a point at which it is no longer materially reduced by additional PV installations. From this point on, some growth in maximum operational demand is forecast, due to other drivers such as population increases. Maximum operational demand in South Australia already occurs late in the day when solar irradiance is low.

Compared to AEMO's previous maximum operational demand forecasts, published in March 2018[7], these new forecasts are higher in all regions towards the end of the 10-year outlook, due to:

- A reduced forecast impact from rooftop PV, as maximum operational demand is projected to move towards sunset sooner than previously expected.
- A reduction in the projected impact of energy efficiency during extreme heatwave conditions. This reassessment is based on new meter data analytics.

[6] Graham, P., Wang, D., Braslavsky, J., and Reedman, L. (2018). *Projections for small-scale embedded technologies*. CSIRO report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[7] AEMO, *Electricity Forecasting Insights*, March 2018 Update, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights.

- Improved understanding of how climate change is projected to increase the magnitude and frequency of heatwave conditions and impact trends in extreme temperatures.
- A higher rate of increase in the expected number of electricity connections over the next 10 years, based on new dwelling construction forecasts provided by the Housing Industry Association (HIA)[8].
- A reduction in projected uptake of new technologies such as energy management systems and battery storage, due to revised assumptions around the payback period, technology cost reductions, and linkages to uptake of PV systems, based on advice from CSIRO. These technologies have potential to provide an energy-shifting role to smooth rooftop PV generation from daytime to evening peak, although their effectiveness will depend on the level of aggregation that occurs.

Supply availability forecasts

AEMO also continues to improve its assessment of key uncertainties that can impact supply reliability, so the market modelling emulates reality as closely as possible. These uncertainties include climate change and extreme weather events, the variability and diversity of intermittent generation, the reliability of thermal (coal- and gas-fired) generation, and the capability of the transmission network.

Through close consideration of real-time operational experience, discussions with external stakeholders, deployment of data integrity checks, and engagement of consultants, AEMO has scrutinised and updated the following inputs:

- Generation deratings – better aligned to recent historical observations under extreme temperatures.
- Generator forced outage rates – increased based on generation surveys which indicated an increasing incidence of forced outages in recent history, reflective of an aging thermal generation fleet.
- Wind and solar resource data – more site-specific assessment of variable renewable generation contribution at times of peak demand for committed resources in new locations.
- Battery charging and discharging profiles – improved transparency, and modelling of two disparate charging profiles and assumed impacts on peak demand:
  - Convenience charging, in which a battery owner uses their storage capacity solely for their own consumption, seeking to minimise their consumption from the grid and hence minimise the cost to them, assuming a flat tariff.
  - Aggregated charging, in which an aggregator acts as an agent for a group of consumers, seeking to maximise the value of that storage to the system and hence reducing operational demand at peak.
- Network performance – improved representation of dynamic line ratings (temperature-dependent), and including the impact of a multitude of potential unplanned line outages, or bushfire risks, on inter-regional transfer capability. While the probability *of any one event* may be small, the probability of *at least one event* coinciding with high demand conditions is higher, and can have a material impact on supply adequacy.
- Committed generation – comprehensive stakeholder survey to capture commitments to construct utility-scale generation and storage in the next 10 years, based on AEMO's commitment criteria. Approximately 5.6 GW of committed new renewable generation, storage, and thermal capacity upgrades are expected to be available in the next few years, and a further 50 GW of proposed projects (mostly renewable generation) are at various stages of development.

Evaluation of unserved energy against the reliability standard

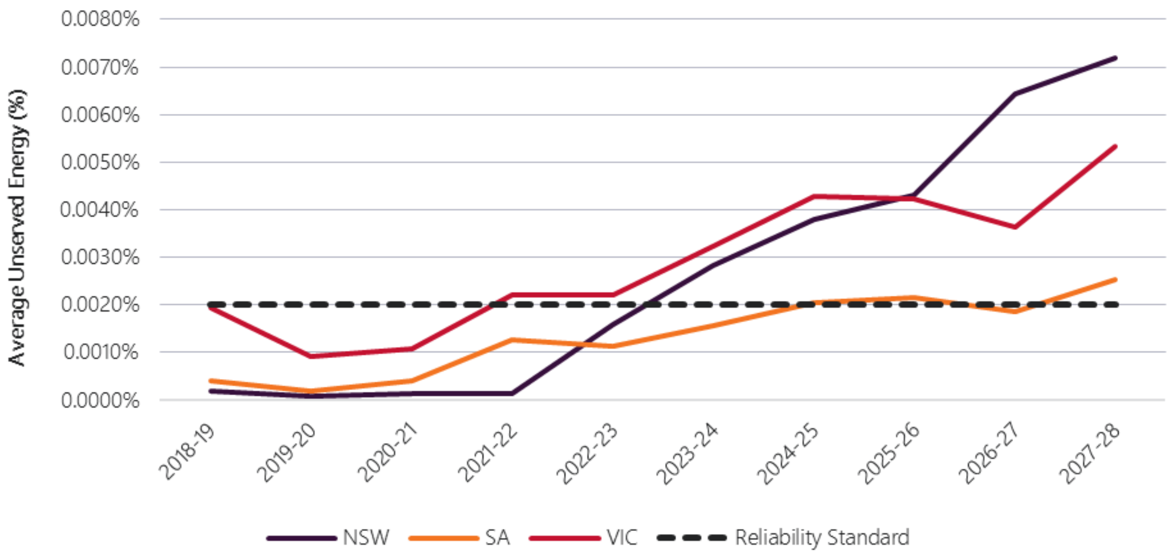
The NEM reliability standard is an economic planning and risk metric that requires expected USE to not exceed 0.002% of consumption per region in any financial year. The USE analysis applies a statistical

[8] ABS Household and Family Projections, Australia, 2011 to 2036, Cat No. 3236.0 and Population Projections, Australia, 2012 (base) to 2101, Cat No. 3222.0, available at http://www.abs.gov.au/AUSSTATS/abs@.nsf/mf/3222.0.

expectation for a future state, using averages across a range of future outcomes, weighted for probability of occurrence. For example, to consider maximum demand variability, AEMO provides forecasts for each NEM region based on both 50% probability of exceedance (POE)[9] and 10% POE demand conditions, and weights each outcome.

Figure 2 shows forecast USE in the next 10 years in Victoria, New South Wales, and South Australia. This forecast is based on Neutral demand forecasts, and assumes no projects being developed beyond those currently committed. It also assumes that AEMO will issue Directions to market participants, if needed, to support reliability under conditions of supply scarcity[10].

Figure 2 Forecast USE outcomes – Neutral demand, only existing and committed projects



The 2018 ESOO details forecast risks to supply in the short term (2018-19, including the coming summer) in Victoria (and also in South Australia, due to the two regions' interconnectedness)[11]. While the projected USE is within the standard, the risks to reliability are forecast to continue in the subsequent two-year period to 2020-21, with minor changes in either supply or demand forecasts capable of changing this reliability assessment. With some announced generation retirements after that period, reliability risks are forecast in Victoria and New South Wales for the rest of the outlook period to 2027-28, but only if there is not sufficient new investment. South Australia is forecast to be close to the standard from 2023-24, while there is no material USE forecast in Queensland or Tasmania in any scenario.

The USE is not a target to secure reliability. Rather, expected USE is an annual average representation of the risk of load shedding, using a range of statistically variable inputs. The actual occurrence of load shedding in a given year can be lower than or over the standard. Outcomes can be considerably higher than the standard with particular combinations of weather events and plant outages. The modelling for the ESOO simulates a large number of possible outcomes and, in addition to reporting the average USE over all simulations, can be used to report a wider range of measures on the level of reliability forecast. Further information is provided in the body of the report by region.

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[9] Probability of exceedance (POE) means the probability, as a percentage, that a maximum demand forecast will be met or exceeded (for example, due to weather conditions). For example, a 10% POE forecast is expected to be met or exceeded, on average, only one year in 10, so considers more extreme weather (also called 1-in-10-year conditions) than a 50% POE forecast, which is expected to be met or exceeded, on average, one year in two.

[10] In times of supply scarcity, AEMO is required to use its reasonable endeavours to utilise RERT in preference to issuing Directions to market participants (NER 3.8.13).

[11] Analysis does not consider pain sharing. The pain sharing principle of the NEM states that load shedding should be spread pro rata throughout interconnected regions when this would not increase total load shedding. This is to avoid unfairly penalising one region for a supply deficit spread through several interconnected regions.

Changes in the make-up and operating complexity of the NEM, including a growing proportion of variable renewable energy generation, both behind-the-meter and on the grid, are contributing to a growing difference in the statistically expected level of USE and exposure to potential supply shortfalls at times of peak demand. The installation of high levels of embedded rooftop PV generation across the NEM is leading to a later and shorter peak in operational demand. Concurrently, the USE measure is becoming more sensitive to weather-driven variations in input assumptions. With increasing growth in variable renewable energy resources, both demand and supply are now exposed to the vagaries of weather, such as wind and solar availability, impacting the ability of the system to meet demand on extreme peak days.

In this report, AEMO does not comment on the ongoing appropriateness of the reliability standard in its current form. However, the changing dynamics of the power system require a full review of the continued appropriateness of the standard as a mechanism to avoid the imposition of higher risk of load shedding than is acceptable or in the public interest.

Short-term actions

In 2018-19, while forecast USE in Victoria is marginally below the reliability standard (0.0019%), there remains a relatively high forecast likelihood (1-in-3 chance) of some USE this summer without further action. Most load shedding is projected to occur under plausible, extreme weather conditions. Specifically, temperatures of 40^{0}C or more in Victoria could be the catalyst for extreme, 1-in-10-year electricity demand conditions, particularly when these temperatures are experienced towards the end of the day when business demand is still relatively high, residential demand is increasing, and rooftop PV's contribution is declining. If these demand conditions were to be experienced in Victoria this summer, approximately 380 MW of additional balancing and firming resources (supply or demand) is projected to be needed across Victoria and South Australia combined to close the gap between expected USE and the reliability standard.

Uncertainties relating to demand and supply indicate a range of possible outcomes which AEMO, as system operator, would need to manage to protect consumers against supply interruptions. Further, uncertainty in NEM forecasts is inevitable, so all estimates of reserve requirements must be regarded as subject to progressive refinement. Minor changes to the outlook for demand or supply could lead to supply shortfalls and result in the reliability standard not being met.

AEMO is continuing to monitor and address risks of supply shortfalls in the lead up to summer 2018-19 as part of the NEM summer readiness program. Summer readiness will again address a range of key areas including the resource capacity and availability issues highlighted in the ESOO, and fuel availability for generation. In particular, the potential impact of the New South Wales drought on water available for hydro generation and as cooling water for thermal generation will be closely monitored and reported in an updated Energy Adequacy Assessment Projection (EAAP) later in the year. Given current weather conditions, bushfires may also threaten the power system this summer, limiting inter-regional transfer capabilities and increasing supply scarcity risks.

The heightened risk and uncertainties identified for Victoria in 2018-19 highlight the need to secure additional resources for this summer to ensure the reliability standard is not exceeded. The ESOO does not include the temporary diesel generation in South Australia that was installed last summer but is not available to the market. It is, however, expected to be available for use as a last resort to avoid load shedding and may be offered for service in the RERT. AEMO is currently evaluating tenders for RERT for summer 2018-19 in Victoria and South Australia (combined requirement). The RERT response may be sourced from a combination of additional supply capacity, energy storage, and demand response. This 2018 ESOO reliability assessment, combined with RERT cost information, will help inform any decision on volumes of RERT to acquire.

Longer-term opportunities

The 2018 ESOO, continuing a theme from the 2017 ESOO and other recent forecasts, highlights that without additional investment and as generation reaches end of technical life and retires, there is a forecast emerging reliability gap across Victoria, New South Wales, and South Australia.

This ESOO modelling incorporated the announced retirements of the Torrens Island A Power Station in South Australia (480 MW, between 2019 and 2021) and Liddell Power Station in New South Wales (1,800 MW, in 2022). As a result, the level of USE is projected to increase significantly after these generation retirements, in the absence of further investment.

Longer-term USE forecasts are higher than in the 2017 ESOO, largely due to a combination of updated maximum demand forecasts, and reductions in generation availability and network transfer capability, as already discussed.

Table 1 shows the forecast emerging reliability gap, defined as the additional MW of firming capability[12] that would be required to meet the reliability standard, after accounting for the ability of additional reserves to provide reliability benefits in other regions[13]. Note that Victoria and South Australia are treated as a single, combined zone for this analysis, because additional firming resources in either region would be able to reduce both regions' USE to below the standard. The table also shows the reliability gap under 10% POE demand conditions, to improve understanding of the risks and power system vulnerabilities under more extreme but plausible weather conditions.

Table 1 Reliability gap – capacity required to meet reliability standard under different demand conditions

	Weighted USE ≤ 0.002% (MW)		10% POE USE ≤ 0.002% (MW)	
	South Australia/Victoria	New South Wales	South Australia/Victoria	New South Wales
2018-19	0	0	380	0
2019-20	0	0	130	0
2020-21	0	0	190	0
2021-22	40	0	483	0
2022-23	40	0	460	380
2023-24	200	150	650	640
2024-25	340	310	790	810
2025-26	330	380	835	885
2026-27	260	620	755	1,130
2027-28	460	700	985	1,220

The emerging reliability gap shown in Table 1 could be closed by a portfolio of resources including utility-scale renewable generation, storage, DER[14], flexible thermal capacity, and transmission, as identified in AEMO's 2018 ISP. In the short term, any gap this summer will be closed by contracting levels of additional supply or demand response under long-notice RERT arrangements, in consultation with relevant jurisdictions.

The Integrated System Plan (ISP)

While AEMO is tracking nearly 50 GW of generation and storage projects in various stages of development, only existing and new generation resources with a formal commitment to construct are included in the core ESOO analysis, in accordance with the National Electricity Rules, to highlight development needs to maintain

[12] Firming capability can be dispatched to maintain balance on the power grid. It can include generation on the grid, storage, demand resources behind the meter, flexible demand, or flexible network capability.

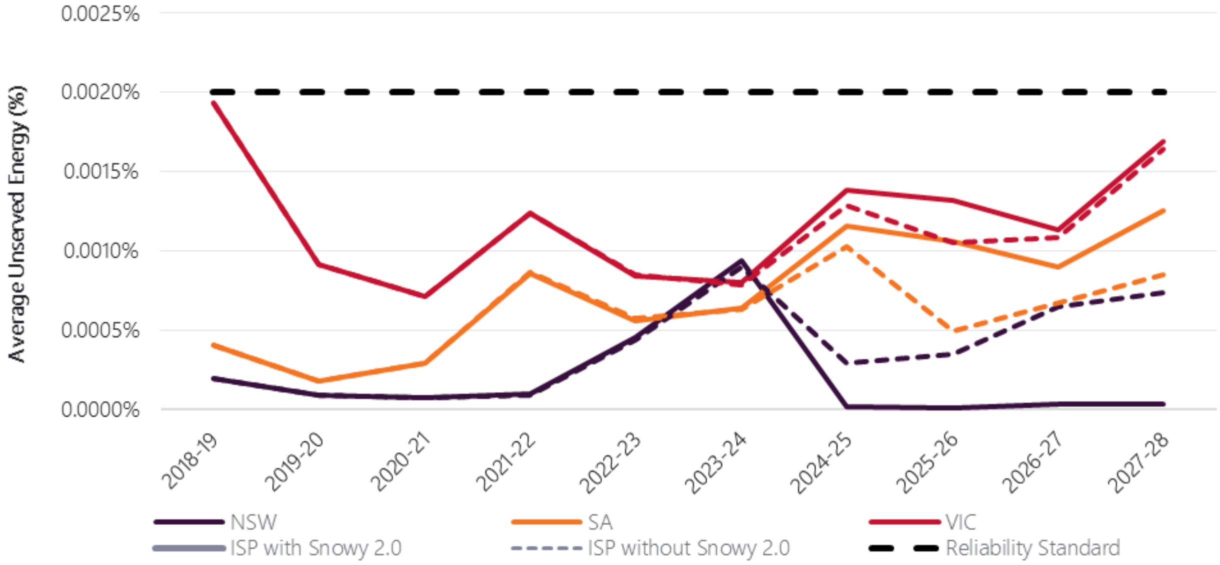
[13] Although South Australia is forecast to be above the reliability standard from 2024-25, the additional reserves added in Victoria would reduce USE to below the standard.

[14] DER can refer to resources, at the distribution or consumer level, which produce electricity or actively manage consumer demand.

reliability. To demonstrate how a portfolio of resources – including renewable generation, storage, flexible thermal generation, DER, and transmission – can meet these development needs, this ESOO also includes a reliability assessment if developments identified in the ISP are implemented.

The ISP projects a range of generation, storage, and transmission investments which, in combination, can meet reliability, security, and emissions requirements in the NEM at the lowest resource cost. This ESOO has also assessed system reliability assuming the portfolio of generation and transmission development identified in the ISP Neutral and Neutral with storage cases[15] was committed. As Figure 3 shows, the effect of both cases is projected to be a substantial reduction in the level of USE, to below the reliability standard[16].

Figure 3 Forecast USE outcomes – Neutral ESOO demand, ISP Neutral development plans



The demand forecasts applied in the 2018 ESOO are higher than those modelled in the ISP, but the ISP modelling was designed to be robust in a range of plausible futures, and the ESOO results indicate that the ISP development plans remain appropriate for addressing emerging risks of supply shortfall, even with higher forecast demand. As AEMO noted in the ISP, the timings and size of actual investments will ultimately respond and adapt to changes in expectations as the future evolves.

The ISP also considered how the current level of transmission congestion significantly limits the ability for reserves to be shared across regions at times of tight supply-demand balance, particularly between Victoria and New South Wales. An increase in the transfer capability of key flow paths would reduce the need for additional generation capacity to be built by taking advantage of diversity in supply and demand between regions, and by better leveraging regions with a surplus of supply, such as Queensland and Tasmania.

Shaping the investment landscape

It is critical that the investment environment and policy and regulatory arrangements, such as those contemplated by the reliability mechanism of the National Energy Guarantee, are capable of supporting a smooth transition to replacement resources as current generation retires. Government and industry must actively work towards creating the landscape for this to occur, without disruption to reliability, and at the lowest cost to consumers.

[15] The ISP Central with storage initiatives 20-year development plan included both Snowy 2.0 and Battery of the Nation proposed large-scale storage developments. Only Snowy 2.0 is included in ESOO modelling for its 10-year outlook period.

[16] Reliability differences in South Australia and Victoria between the two ISP development plans are due to minor differences in the projected size and timing of new investments in these regions in ISP modelling, and are not directly attributable to Snowy 2.0. Very small differences in future supply are amplified when considering reliability.

This ESOO analysis helps inform AEMO's broader transparent and evidence-based approach to understanding, managing, and planning the solutions needed to support the development of the NEM. AEMO is working with the Energy Security Board, Reliability Panel, and industry to identify proactive policy, regulatory, and market reforms that may be required to facilitate investment in the public interest, including:

- Designing a coordinated approach to transmission planning and timely development, that supports positive consumer outcomes in the energy transition, as identified in the Finkel review and promoted in AEMO's ISP.
- Promoting the market design changes contemplated in the Finkel *Blueprint for the Future* Security of the NEM[17] and AEMC's Reliability Frameworks Review[18], and the enduring policy certainty needed to support efficient, technology-neutral investment decisions in dispatchable resources and DER that achieve targeted emissions levels while maintaining system reliability.
- Working with the Reliability Panel to determine whether the existing planning reliability standard, and the frameworks to operationalise this standard, remain appropriate in a future where the operational demand is becoming peakier due to high uptake of rooftop PV and climate change, and power system reliability is more exposed to the vagaries of weather.
- Developing an integrated strategy for DER considering operational processes, standards, integration processes, market frameworks, data visibility, and network incentives to more effectively manage market conditions. By 2028, based on the levels of behind-the-meter battery installations and default levels of aggregation assumed in this ESOO analysis[19], market mechanisms to facilitate greater levels of DER coordination could provide up to 500 MW of additional supply at times of high demand across regions.
- The recent reinstatement of long-notice RERT as a safety net to help mitigate supply scarcity risks in the short term.

Collectively, these actions can simultaneously identify required and likely investments, provide pathways for orderly retirements and investment in new resources to best meet established and new policy and economic objectives, and enable innovation by removing existing and emerging barriers to entry and competition.

Monitoring outcomes

To assist planning and facilitate informed decision-making, AEMO aims to identify and communicate any emerging risks to supply using the latest information provided from market participants, and will issue updates to this ESOO if there are significant changes in the outcomes. For the 2018 ESOO, AEMO consulted extensively with industry stakeholders and further improved the quality of input demand and supply data and analysis, to ensure the veracity of the reliability forecasts. This included collaboration with climate scientists to better understand the impacts of climate change, extreme weather events, and geographic diversity of renewable generation on demand and supply.

AEMO will continue to work with stakeholders and through the Forecasting Reference Group to improve demand forecasts, and will closely monitor actual supply to the market so reliability modelling closely represents performance. AEMO will engage with experts and consult with stakeholders to develop a range of demand and supply forecast accuracy measures by December 2018. These are likely to include specially developed techniques to measure the accuracy of probabilistic forecasts, especially where they relate to the 'long tail' of distributions. In a period of transition, it is also important to monitor key leading indicators to provide early information on changing trends which may impact on forecasts.

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[17] Available at https://www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market.

[18] See https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review.

[19] The assumed contribution from distributed storage to meeting peak demands across Victoria, South Australia, and New South Wales is approximately 35% of total installed battery capacity by 2028.

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1. Introduction

1.1 Purpose and scope

The *Electricity Statement of Opportunities* (ESOO) provides information on committed electricity supply information, planned plant retirements, network capabilities, and constraints provided by industry, and operational consumption and maximum demand forecasts, and identifies potential unserved energy (USE) in excess of the reliability standard over a 10-year outlook period. Demand forecasts are extended to 20 years. AEMO performs this evaluation under a range of demand and supply scenarios.

The purpose of this study is to provide information to market participants to help them make informed planning decisions in relation to the National Electricity Market (NEM). The period covered by the current ESOO is from 2018-19 to 2027-28. Operational consumption and maximum demand forecasts are provided over a 20-year period from 2018-19 to 2037-38 because these forecasts are used by stakeholders for a range of purposes, including longer-term planning studies.

1.2 Key definitions

Unserved energy (USE) is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). This may be caused by factors such as insufficient levels of generation capacity, demand response, or network capability, to meet demand.

The reliability standard in the NER specifies that expected USE[20] should not exceed 0.002% of total energy consumption in any region in any financial year.

A reliability gap represents the additional quantity of dispatchable[21] capacity or equivalent, expressed in megawatts (MW), that AEMO projects will be needed to maintain reliability at levels that meet the reliability standard. In determining this reliability gap, AEMO has considered inter-regional reserve sharing.

Consumption and demand forecasts in this report refer to operational consumption/demand (sent out)[22]. This is the consumption to be supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator).

Consumption forecasts for each sector (residential and business) are delivered consumption, meaning the electricity delivered from the grid to household and business consumers. Annual operational consumption forecasts include this forecast delivered consumption for all consumer sectors, and electricity expected to be lost in transmission and distribution.

Underlying demand means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' rooftop photovoltaic (PV) and battery storage.

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20 The USE that contributes to the reliability standard excludes power system security incidents resulting from multiple or non-credible generation and transmission events, network outages not associated with inter-regional flows, or industrial action (NER 3.9.3(b)).

21 The dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target', and incorporates how controllable the resources are, how much they can be relied upon, and how flexible they are. For more information, see AEMO's *Power System Technical Requirements*, March 2018, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

22 See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/Operational-Consumption-definition---2018-update.pdf for further information on the operational demand definition.

Maximum and minimum demand means the highest and lowest level of electricity drawn from the grid at any one time in a year. These forecasts are presented sent out (the electricity measured at generators' terminals, excluding generator auxiliary loads). Maximum and minimum demand forecasts can be presented with a 50% probability of exceedance (POE) – meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions – or a 10% POE (for maximum demand) or 90% POE (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called 1-in-10).

All times in the ESOO are NEM time, that is, Australian Eastern Standard Time, which does not include daylight savings.

1.3 Forecasting supply reliability

The current NEM reliability standard is set to ensure that sufficient supply resources exist to meet 99.998% of annual demand for electricity in each region. The standard allows for a maximum expectation of 0.002% of energy demand to be unmet in a given region per financial year. The USE that contributes to the reliability standard excludes power system security incidents resulting from multiple or non-credible generation and transmission events, network outages not associated with inter-regional flows, or industrial action.

To forecast reliability of supply for the NEM in the 2018 ESOO:

- New demand forecasts have been developed for all regions, taking into account the latest information on economic and population drivers and trends in business and household consumer behaviour. The forecasts for operational or on-grid consumer demand account for forecasts for growth in distributed solar generation (rooftop PV) and storage.
- The supply available to meet this demand has been updated to include the latest information on generation in the NEM which is connected or committed to connect to the grid.
- The performance of existing conventional generation has been reviewed based on historical performance data, and the modelling of its behaviour has been refined to better reflect recent operating experience. Some allowance has also been made for network outages associated with inter-regional flows, recognising the importance of major interconnectors in delivering reliable supply to consumers.

The modelling then uses a statistical approach, which calculates an average USE over a number of demand outcomes (based on eight historical reference years of weather) and random generator outages, weighted by likelihood of occurrence, to determine the probability of any supply shortfalls. These shortfalls have been expressed in terms of the expected USE and compared to the NEM reliability standard. A range of other measures have also been computed to provide a broader picture of the risk to reliable supply, and future development needs.

Pain sharing is not included in ESOO modelling. Instead, the annual USE reported in a region reflects the source of any supply shortfall and is intended to provide participants with the most appropriate locational signals to drive efficient market responses.

The ESOO model assesses the ability of existing and committed generation to meet forecast demand. Investment is possible with sufficient lead time, provided a conducive investment landscape exists. In the medium to longer term, the ESOO highlights opportunities for market investment to meet consumer needs, and the risks if investment is not forthcoming.

Within an operational timeframe, AEMO will endeavour to manage the market to avoid USE with the resources available. This may include contracting additional supply or demand response, under long-notice Reliability and Reserve Trader (RERT) arrangements. The ESOO analysis is therefore an important input to AEMO's operational planning for summer readiness[23], as further market investment above what is already committed is unlikely to be available in the short term.

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[23] For more information about how AEMO plans for summer, see http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report.

Since the release of the 2017 ESOO, scrutiny of and debate about reliability of supply has continued to grow. Changes in the make-up and operating complexity of the NEM, including a growing proportion of variable renewable energy generation, both behind-the-meter and on grid, are contributing to a growing difference in the expected level of statistically averaged incidences of resource insufficiency and exposure to potential supply shortfalls at times of peak demand.

In this report, AEMO does not comment on the ongoing appropriateness of the reliability standard in its current form. However, the changing dynamics of the power system require a full review of the continued appropriateness of the standard as a mechanism to avoid the imposition of higher risk of load shedding than is acceptable or in the public interest.

Over the last few months, AEMO has been investigating the changing dynamics of the power system and their potential implications for planning and operational reliability[24] outcomes. This work is considering the changing nature of reliability risks, and suitability of existing standards, processes, and procedures to manage these risks into the future. AEMO will soon publish a short paper on its observations to date, to inform discussions regarding reliability standards in the NEM.

1.4 Scenarios

Reliability forecasts are impacted by two key factors in the 10-year outlook:

- Demand and distributed energy resources (DER) forecasts and trends, outlined in Chapters 2 and 3.
- Supply forecasts, including generation, transmission, and storage developments, and availability, outlined in Chapter 4.

These forecasts are influenced by the existing energy landscape and assumptions around future trends. There is scope for considerable uncertainty in future outcomes. Acknowledging this, the 2018 ESOO modelling has been performed under three scenarios and two sensitivities with varying outlooks for future supply and demand, based on scenarios used in AEMO's inaugural *Integrated System Plan* (ISP)[25].

The three core ESOO scenarios assess supply adequacy of existing and committed generation, storage and transmission projects, under three different demand projections driven by faster or slower transformative change in the NEM, and higher or lower grid consumption:

- Neutral pace of change (Neutral) scenario – this scenario assumes a range of mid-point projections of economic growth, future demand growth, electric vehicle uptake and fuel costs, and existing market and policy settings. It also assumes moderate growth in DER aggregation, such that aggregated distributed batteries can be treated and operated as virtual power plants rather than operated to maximise the individual household's benefit.
- Slower pace of change (Slow change) scenario – under this scenario, economic growth is weak, reducing business investment and resulting in some industrial closures. Overall discretionary income at a household level is lower, fewer electric vehicles are purchased, and there are lower levels of investment in energy efficiency. Regulatory frameworks for DER are assumed to advance at a faster rate than technology advancements, leading to relatively high DER aggregation. The net effect is lower operational (grid) consumption, a smoother operational load profile (due to a higher level of demand-based resources and high DER aggregation), and a slower power system transformation, relative to the Neutral scenario.
- Faster pace of change (Fast change) scenario – under this scenario, economic growth is strong, increasing overall discretionary income at a household level, and stronger emission abatement aspirations are economically sustainable. With higher population and more robust economic conditions supporting increasing demand for services reliant on electricity, demand for electricity energy would be higher than projected under the Neutral scenario, including greater uptake of electric vehicles. DER technology

[24] Operational reliability refers to the management of supply and demand over operational timeframes (days, hours, minutes).

[25] The 2018 ISP and associated documents and information are available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

improvements are assumed to advance more rapidly than the regulatory frameworks needed for DER to become a reliability resource, leading to relatively low DER aggregation. The net effect is higher operational (grid) consumption, a more 'peaky' operational load profile (due to lower demand-based resources and low DER aggregation), and a faster power system transformation, relative to the Neutral scenario.

The variations in key inputs assumed in each demand scenario are summarised in Table 2.

Table 2 Demand forecasting scenarios used for the 2018 ESOO

	Neutral	Slow change	Fast change
Economic growth & population outlook	Neutral	Weak	Strong
Rooftop PV – up to 100 kW	Neutral	Neutral	Neutral
Non-scheduled PV – from 100 kW to 30 MW	Neutral	Neutral	Neutral
Electric vehicle uptake	Neutral	Weak	Strong
Battery storage installed capacity	Neutral	Neutral	Neutral
Battery storage aggregation by 2050	45 %	90 %	10 %
Electric vehicle convenience charge[A] by 2050	30 %	10 %	50 %

A. 'Convenience charge' is a profile in which electric vehicles are assumed to predominantly be charged as soon as drivers get home.

Differences between these scenario themes and those used in the March 2018 *Electricity Forecasting Insights* (EFI) Update[26] are intended to increase the spread of possible grid consumption and demand outcomes around the Neutral scenario. Key differences in the 2018 ESOO are:

- The new scenarios used the Neutral trajectory for PV for all scenarios (as opposed to higher PV uptake being assumed under strong economic growth conditions, which would lead to less operational demand).
- A percentage of behind-the-meter batteries were treated in aggregate in the new scenarios, to allow the examination of batteries operating as virtual power plant (so-called 'smart' batteries) to support system peak demand, rather than individual household benefit.

These core ESOO scenarios considered only existing and committed[27] generation and transmission developments and retirements. The demand response forecast used in these scenarios was sourced from the March 2018 EFI Update[28], and represents current estimated levels.

Two additional supply sensitivities have also been modelled in this 2018 ESOO, based on the updated ESOO Neutral demand but assuming additional development consistent with the portfolio of new resources and transmission identified for development in the first 10 years of the ISP base cases[29]:

1. ISP without Snowy 2.0 ("Base development plan" in the ISP).
2. ISP with Snowy 2.0 ("Base development plan with storage initiatives" in the ISP).

The purpose of the supply sensitivities is to demonstrate how a portfolio of resources including utility-scale renewable generation, storage, DER, demand response, flexible thermal capacity, and transmission, can provide the firming capability required to close any emerging reliability gap. These sensitivities incorporate additional generation installations and retirements, forecast growth in demand response, as well as

[26] Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights.

[27] This approach is mandated by NER 3.13.3(q)(2). Commitment criteria are outlined under the Background information tab in each regional spreadsheet on AEMO's Generation information web page, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. These criteria relate to land for the development, contracts to acquire major components of plant and equipment, planning and approvals, financing, and construction and operating dates.

[28] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation.

[29] In the ISP, the Base development plan with storage initiatives included both Snowy 2.0 and Battery of the Nation, however only Snowy 2.0 is proposed within the ESOO's 10-year outlook period.

augmentation of transmission across the NEM. A detailed description of the development plans is provided in Section 4.

The ISP development plans were modelled earlier in 2018, using the Neutral demand scenario assumptions described in Table 2, but using older input data. While the 2018 ESOO demand forecasts differ from the projections assumed in developing ISP portfolio development plans, the ISP development plans were designed to be robust to changes in input assumptions, including demand. The USE outcomes that resulted from the ISP development plans being modelled in this ESOO without adjustment show the robustness of these plans.

1.5 Improvements for 2018 ESOO

Increased variability and uncertainty on both the supply side and demand side, a tighter supply-demand balance, and increased climatic variability, place greater emphasis on forecasting, and the understanding and quantification of uncertainty.

The 2018 ESOO builds on earlier versions by enhancing the quality of the data used to construct the forecasts. It also addresses changes in supply and network performance in greater detail, using augmented data sets calibrated to historical observations.

AEMO has consulted extensively with industry stakeholders, primarily through its Forecasting Reference Group[30] (FRG), to continually improve the veracity of the reliability forecasts, and acknowledges the ongoing contributions made by the FRG to assist AEMO in improving the forecasting process.

AEMO has also been working in collaboration with the Bureau of Meteorology (BoM) and CSIRO to better understand the impacts of extreme weather on supply and demand forecasting, now and in the future.

1.5.1 Supply forecasting improvements

Since the 2017 ESOO, AEMO has undertaken a comprehensive review of modelling assumptions and methodologies to ensure that the market modelling closely reflects real operational conditions. The supply modelling improvements implemented include:

- Committed generation – comprehensive stakeholder surveys to capture new generation developments, ensuring that the model includes all new generation and storage projects that have a commitment to construct. Rigorous validation procedures have been implemented by comparing information on new projects against other sources such as the Clean Energy Regulator's register.
- Generator ratings and performance – AEMO has reviewed all generator summer capacities to ensure that these values reflect likely performance under summer peak conditions. AEMO has engaged with a number of market participants to ensure these assumptions are accurate. AEMO has also implemented higher outage rates for many generators based on historical outage data provided by market participants. These outage rates are reflective of an aging thermal generation fleet.
- Wind and solar resource data – more site-specific assessment of variable renewable generation contribution at times of peak demand for committed resources in new locations.
- Battery behaviour – implemented two alternative charge/discharge profiles for residential battery storage reflecting both convenience charging and aggregated charging (see Section 2.2.2).
- Network performance – undertaken a detailed review of the modelling of weather-dependant dynamic line ratings. The updated line rating information more closely reflects historical network performance. The ESOO also includes the impact of unplanned line outages for three key transmission flow paths to capture the impact of line outages and bushfires on inter-regional transfer capabilities.

[30] See http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Forecasting-Reference-Group for more information.

- Weightings of POE demand outcomes – reviewed, validated, and factored in 90% POE outcomes conservatively, assuming zero USE under these demand conditions (see Appendix A3 for more information).
- Number of random samples – the number of random samples of generator outages has been increased. The Neutral scenario outcomes are based on 1,600 simulations, and 800 simulations were modelled for all other scenarios. In the 2017 ESOO, 210 simulations were modelled for each scenario. The increase in the number of simulations improves the accuracy of the USE forecast distribution, and better captures the range of possible combinations of generator outages.

1.5.2 Demand forecasting improvements

To improve consumption and maximum demand forecasts for this year's ESOO, AEMO implemented the following new methodologies:

- Improvements to AEMO's short-term (2-3 years) business and residential forecast models – AEMO constructed the short-term consumption model using the latest meter data for residential and business consumers up to 30 June 2018 (data which was previously unavailable). These models improved estimates of weather-sensitive load components, and the energy efficiency forecasts have been mapped directly to these to improve the allocation of energy efficiency savings from cooling and heating, and the effect on maximum demand forecasts.
- Weather and climate impacts – AEMO has improved the approach for climate change projections and the impact on trends in extreme temperatures, leading to anticipated increases in future maximum demand. AEMO has enhanced the methodology that more dynamically identifies when climate change impacts are likely to drive greater increases in high/extreme temperature (and maximum demand) than average temperature.
- PV non-scheduled generation (PVNSG) – for this fast-growing segment covering solar PV installations between 100 kW and 30 MW, AEMO last year assumed the same growth rate as commercial-scale PV (10 kW to 100 kW). This year, AEMO engaged with CSIRO to derive a dedicated forecast of installed capacity for PVNSG.
- Emerging developments in energy management systems as well as electric vehicle charging profiles – these are expected to alter demand in more dynamic ways. Using recently available meter data, AEMO has improved the forecast methodology related to battery and electric vehicle charging to ensure the growing sophistication in the demand profiles of these activities represents the evolution of developments observed in the NEM and reflects technological development and consumer tariff offerings.

1.6 Additional information for 2018 ESOO

Table 3 provides links to additional information provided either as part of the 2018 ESOO accompanying information suite, or in related AEMO planning information.

Table 3 Links to supporting information

Information source	Website address and link
2018 ESOO supplementary results and data files	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2018 ESOO model and user guide	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Forecasting data portal	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting
2018 ESOO Constraints Workbook	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

Information source	Website address and link
Market modelling methodology report	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database
2018 Demand Forecasting Methodology	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Archive of previous ESOO reports	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/NEM-ESOO-Archive
Generation Information web page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
MT PASA	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy
Maps and network diagrams	http://www.aemo.com.au/aemo/apps/visualisations/map.html
RERT Panel EOI	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT-panel-expressions-of-interest
Integrated System Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

2. Trends in demand drivers

Australia's population reached 25 million in August 2018 and is projected to continue to grow at between 1% and 1.3% a year over the forecast period[31], leading to more electricity connections, predominantly in capital cities.

Household electric appliance use, along with the capacity and functionality of these appliances, has increased since 2009. This trend is forecast to continue over the next 20 years. Households are more reliant on electricity than ever due to increases in larger capacity white goods, larger televisions, more web-connected devices, and more heating and cooling capability.

A similar trend is also seen in the business sector with increased growth in businesses, heating and cooling needs, manufacturing capacity, computer hardware, data storage, and business-related appliances.

Despite increasing reliance on electricity, operational consumption, (the amount of electricity consumed from the grid), has declined across the NEM since 2009 as growth in rooftop PV, improving energy efficiency, and a range of other factors have offset increased electrical appliance use. Rooftop PV installation costs have continued to come down, with current pay-back periods estimated in the order of five years[32].

There has also been a structural change in the business sector, with the services/commercial sector and food and beverage manufacturing growing relatively strongly, while energy-intensive manufacturing has been in decline. The latter may continue its relative decline when facing tough economic conditions, although it is more resilient today than in the past. Apart from mining and coal seam gas (CSG) developments for liquefied natural gas (LNG) export, there appears little scope for growth amongst the largest energy users, beyond incremental lifts of existing capacity.

Weather continues to be a strong driver of peak demands for energy for heating and cooling, making it increasingly important to understand weather dynamics over summer periods in the short term and the projected impact of climate change over the longer term. According to the Climate Change in Australia website[33], climate scientists have very high confidence that Australia's average temperature will increase, with more hot extremes and fewer cold extremes. This will have a greater effect on system peak demand than on annual electricity consumption, by increasing cooling load and reducing winter heating load.

The energy industry is being transformed by technological advancements which are changing the generation mix and creating opportunities for increased consumer engagement when it comes to choice and energy supply solutions. AEMO observes that battery storage and electric vehicles continue to gather momentum internationally and in Australia, with industry and consumers keen to explore the opportunities and challenges presented by these new technologies.

Over the past 12 months, operational electricity consumption was slightly higher than 2016-17 actual consumption (0.07%) but slightly less than forecast in the 2017 ESOO (0.32%). The difference from the

[31] ABS Household and Family Projections, Australia, 2011 to 2036, Cat No. 3236.0 and Population Projections, Australia, 2012 (base) to 2101, Cat No. 3222.0, available at http://www.abs.gov.au/AUSSTATS/abs@.nsf/mf/3222.0.

[32] Graham, P., Wang, D., Braslavsky, J., and Reedman, L. (2018). *Projections for small-scale embedded technologies*. CSIRO report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[33] BOM & CSIRO, Climate Change in Australia, available at https://www.climatechangeinaustralia.gov.au/en/.

forecast was driven by reduced consumption in the residential sector, as well as the aggregate impact of more installations of rooftop PV systems than expected, particularly in the business sector. Minor changes in consumption through energy efficiency measures and the consumer behavioural response to high electricity prices had a minor impact on changes in the previous year's aggregate demand.

For the 2018 ESOO, consumption and demand forecasts have been updated to capture these latest trends and projections of these key drivers. The main input changes, compared to the March 2018 EFI Update[34], included:

- Updated economic outlook.
- Updated small-scale technology forecasts for electric vehicles, battery storage systems, and PV systems (both rooftop PV, up to 100 kilowatts [kW], and PVNSG, between 100 kW and 30 MW) prepared by the CSIRO[35].
- Updated energy efficiency forecasts, based on work prepared by *Strategy. Policy. Research.*[36].
- Updated retail price outlook, residential connections forecast, gas-to-electric fuel switching forecast, and economic forecasts.
- Updates of large industrial consumption based on surveys and interviews with large energy users.
- Inclusion of half-hourly climate change information within the long-term maximum demand forecasts.
- Updated time-of-day electric vehicle charge profiles based on different incentive assumptions to shift electric vehicles charging from convenience charging to charging overnight or during the solar trough impacting minimum and maximum demand.
- Incorporation of un-aggregated and aggregated battery splits. The different scenarios provide different splits for battery convenience use versus aggregate batteries operating as a virtual power plant and included in the supply available to meet operational demand (see Section 1.4).

This section summarises some of these key input assumptions.

2.1 Economic and demographic outlook

Economic and demographic projections have a large bearing on electricity consumption forecasts, either explicitly in the modelling, or inherently in shaping projected consumer preferences and behaviour. Dynamics underpinning the economic and demographic drivers considered in the modelling are explained below[37].

2.1.1 Gross State Product

As the global economy is projected to strengthen and the domestic economy to expand (spurred by increased infrastructure spending and business investment), Gross State Product (GSP) is forecast to grow at 2.7% annually on average across the NEM in the short term (0-5 years). Beyond this, GSP is forecast to transition to an average long-term growth rate of 2.4% annually[38], in line with labour force participation and productivity growth[39].

[34] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights.

[35] Graham, P., Wang, D., Braslavsky, J., and Reedman, L. (2018). *Projections for small-scale embedded technologies*. CSIRO report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[36] *Strategy. Policy. Research*. *Energy Efficiency Impacts on Electricity and Gas Demand to 2037-38,* April 2018. Report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[37] These economic projections were developed by an economic consultant, according to AEMO's scenario requirements, for the purpose of producing the electricity demand forecasts for this ESOO. The index data series of the economic forecasts are available on AEMO's forecasting data portal at http://forecasting.aemo.com.au.

[38] GSP growth rates were calculated as an average of the growth rates in the NEM regions, segmented by short term (0-5 years) and beyond (6-20 years).

[39] Based on 40 years of historic economic data.

Scenario variations relative to the Neutral scenario arise from assumed shocks to the global economic outlook, population, and labour productivity.

These were applied symmetrically to the Fast change and Slow change scenarios. In the Fast change scenario, stronger global economic outlook, higher population growth rate, and higher labour productivity result in a higher rate of increase in GSP (3.4% annually on average). The reverse is applied to the Slow change scenario (1.4% annually on average). The deviation in scenario projections becomes more prominent beyond the first five years of the forecast period.

2.1.2 Household Disposable Income

Household Disposable Income (HDI) is projected to experience minimal growth in the next two years, a result of stagnating wages offsetting any benefits from reduced inflationary price pressures for consumers. Beyond this, projected HDI increases as wages are forecast to grow, led by a strengthening domestic economy. HDI is used as a proxy to indicate consumer confidence.

The same shocks as in the case of GSP were applied symmetrically to the model to get the HDI projections for the Fast change and Slow change scenarios. These shocks impact HDI largely through their effect on wages. In the Fast Change scenario, faster increases in wage growth spur household spending, and in the Slow change scenario, prolonged stagnated wages reduce household spending.

2.1.3 Population and connections

Population is a main driver of electricity demand, directly affecting the number of residential and non-residential (businesses and service sector needed to support the population) connections. The number of new residential connections is also driven by social factors such as changes to the household structure.

AEMO assumes a single residential electricity connection for each completed dwelling over the 20-year forecast period. In the short term, the new connections forecast is based on the Housing Industry Association (HIA) dwelling completion forecasts, while in the longer term it uses the growth rate from the Australian Bureau of Statistics (ABS) housing and population forecasts[40], as outlined in Table 4 for the Neutral scenario.

Non-residential connections are forecast using the economic growth outlook in each state and territory, which again takes into account forecast population growth according to ABS.

The total number of connections is projected to increase by about 27% over the 20-year outlook period, or by about 1.3% annual growth on average. Table 4 shows this is largely driven by higher connections growth projected for New South Wales, Queensland, and Victoria, as these regions face stronger population growth than other regions.

Table 4 Forecast connections growth by region – Neutral scenario

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Dwelling	Population	Dwelling	Population	Dwelling	Population	Dwelling	Population	Dwelling	Population
2018-19	1.5	1.3	1.8	1.9	1.5	1.0	0.9	0.6	2.1	1.7
2022-23	1.2	1.4	1.8	1.8	0.9	0.9	0.5	0.5	1.6	1.6
2027-28	1.1	1.3	1.6	1.6	0.8	0.8	0.4	0.4	1.4	1.4
2037-38	0.8	1.1	1.4	1.2	0.6	0.6	0.1	0.1	1.2	1.2

[40] ABS Household and Family Projections, Australia, 2011 to 2036, Cat No. 3236.0 and Population Projections, Australia, 2012 (base) to 2101, Cat No. 3222.0, available at http://www.abs.gov.au/AUSSTATS/abs@.nsf/mf/3222.0.

2.2 Small-scale embedded technologies

Small-scale embedded technologies include rooftop PV systems, battery storage, and electric vehicles. AEMO engaged CSIRO to produce forecasts for these technologies for a low, medium, and high trajectory. The electric vehicle forecasts were applied to the Slow change, Neutral, and Fast change scenarios respectively. In line with the ISP, the medium PV and battery storage forecasts were used across all three scenarios.

2.2.1 Rooftop PV and PV non-scheduled generation

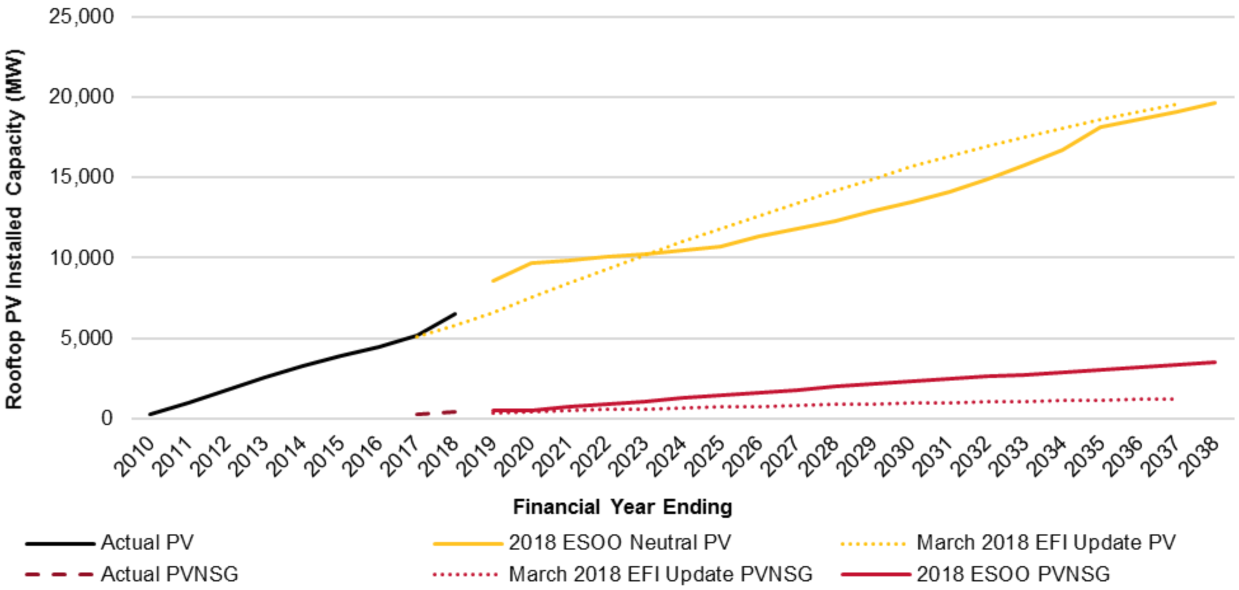
PV systems continue to be installed at a very high rate, with 2017-18 being the highest period of growth in the sector since installations were first recorded. In 2017-18, about 1,300 MW of new capacity was installed, bringing the total rooftop PV capacity across the NEM to approximately 6,500 MW. In Queensland and South Australia, more than 30% of households now have rooftop PV systems installed, with the remaining states sitting at approximately half of that penetration[41].

The rooftop PV forecast shows:

- In the short term (0-5 years), the high growth rate is forecast to continue, driven in part by the recent high retail prices consumers have experienced, along with the small-scale technology certificates (STCs) subsidy.
- In the medium term (5-10 years), slower growth is forecast, as retail prices are projected to lower and as the STC incentive falls to zero by the year 2030.
- In the long term (10-20 years), the rate of installation is forecast to increase again as further reductions in PV system costs are expected in time and retail prices are forecast to be higher.

Figure 4 shows the rooftop PV forecast for the 2018 ESOO and compares it with the March 2018 EFI Update. Differences reflect the assumptions used for each forecast (retail prices, technology costs, tariff structures, household forecasts) and also the recent ramp-up in installations over the past year.

Figure 4 NEM rooftop PV and PVNSG installed capacity comparison, actual and forecast, 2009-10 to 2037-38, and compared to March 2018 EFI Update



The forecast for PVNSG (PV non-scheduled generation between 100 kW and 30 MW) is for strong growth, with total installed capacity of approximately 3,500 MW by 2037-38, over three times higher than the forecast

[41] According to Australian PV Institute Solar PV status (at 17 August 2018), at http://pv-map.apvi.org.au/historical.

in the March 2018 EFI Update. This change is due to more up-to-date Clean Energy Regulator data for commercial systems, which indicate a recent surge in installations, and an updated methodology (explained in the CSIRO report)[42].

High adoption rates of rooftop PV and PVNSG not only reduce the requirements to source electricity from grid-based generators, but also change the load shape at a level not observed in history (for example, minimum demand occurring in the middle of the day and peak-demand shifting further into the evening).

2.2.2 Battery systems

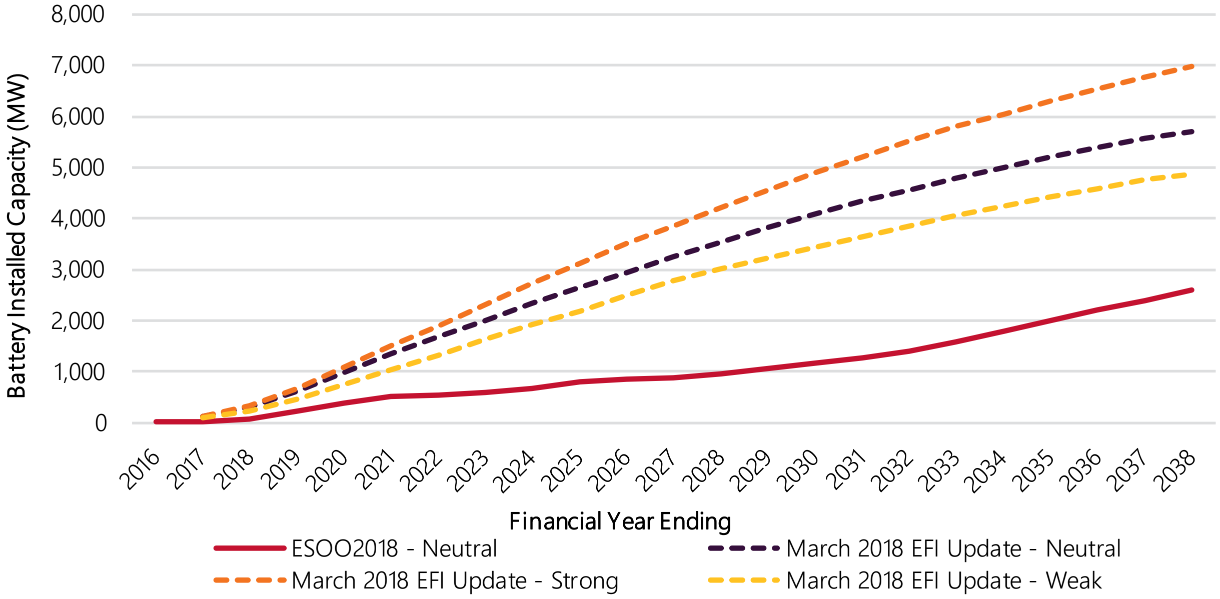
Dependent on pricing incentives, battery storage technology may further change the demand profile, by enabling households to store and use lower cost energy from the sun during the time of evening peak use.

Across the NEM, uptake of business and residential behind-the-meter battery systems by the end of the 20-year outlook period is forecast to be 2.6 gigawatts (GW), less than half the level of uptake projected in 2017 ESOO (5.7 GW). As discussed in CSIRO's report[43], this is due to lower forecast retail electricity prices leading to a less favourable payback period, and different assumptions around tariff structures, technology costs, and other household factors in the forecast horizon[44].

Figure 5 shows the Neutral forecast for small-scale battery installed capacity in the 2018 ESOO (the solid line) is lower than the March 2018 EFI Update (the dotted lines).

The majority of these batteries are assumed to be installed as part of integrated solar and battery systems, since CSIRO's analysis suggests that stand-alone batteries are currently uneconomical. By the end of the forecast, some 15% of residential PV systems are projected to be integrated with batteries across the NEM[45].

Figure 5 NEM battery installed capacity forecast, 2015-16 to 2037-38, Neutral scenario compared to March 2018 EFI Update, all scenarios



[42] Graham, P., Wang, D., Braslavsky, J., and Reedman, L. (2018). Projections for small-scale embedded technologies. CSIRO report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[43] Ibid.

[44] As more information becomes available about how the technology is adopted and used, projections would likely change in response to different incentives that may be put in place in future, for example, to encourage community storage.

[45] Assuming a 5 KW PV system and 5 KW battery system.

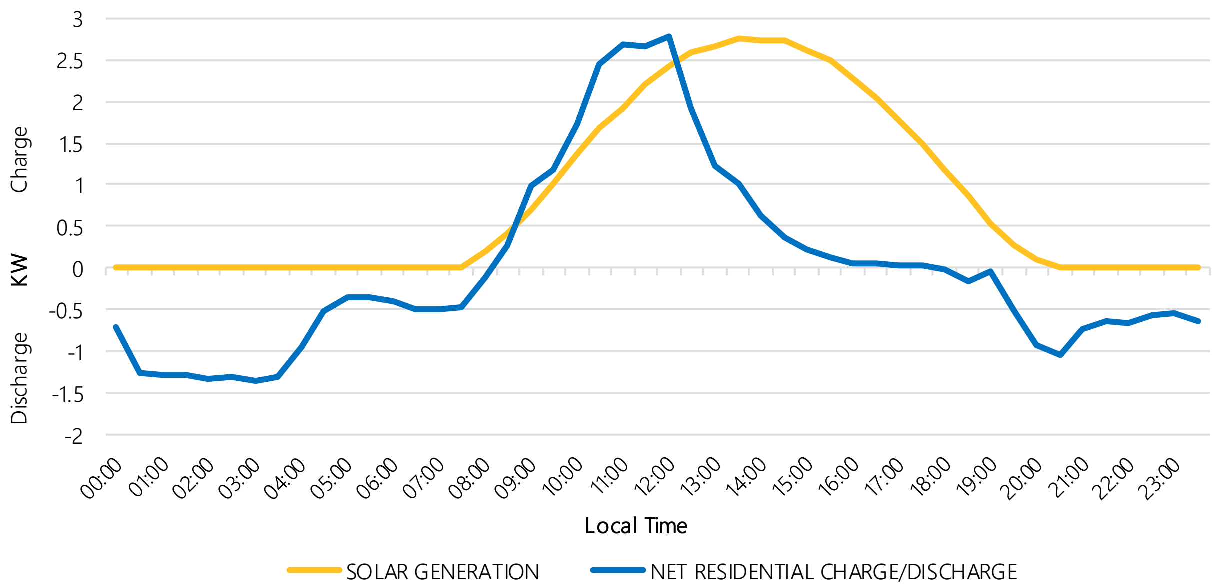
While the overall NEM battery uptake forecast this year is lower, South Australia has a higher battery forecast over the next five years, as this year's modelling incorporated recent state government policy supporting the installation of 40,000 residential batteries[46].

For the 2018 ESOO, AEMO assumed one forecast trajectory for battery uptake, adopting the neutral/moderate scenario provided by CSIRO. However, the Slow change, Fast change and Neutral demand forecasts assumed different levels of battery aggregation, discussed in Section 1.4.

In the Neutral scenario, no behind-the-meter batteries were initially assumed to be aggregated, scaling up to 28% of batteries by 2038. These aggregate batteries are schedulable and operate as a virtual power plant, meaning they are timed to discharge to maximise value to the system, rather than to individual households. In the ESOO, these were modelled explicitly as supply options that are typically dispatched at times of high demand, that is, in the same way as utility-scale batteries.

The role of behind-the-meter batteries in helping maintain system reliability depends on the future charge/discharge profile assumed. For those remaining 72% of batteries not assumed to be aggregated, the ESOO 2018 adopted the charge/discharge profile shown in Figure 6.

Figure 6 NEM battery charge/discharge profile overlaid with PV generation (profile in February assuming a 5 kW battery and 5 kW PV system)



This figure shows a typical profile in February, assuming a 5 kW battery system[47] (13 kWh) with 5 kW of panels. The profile, called 'convenience charging', assumes households will consume what they can from PV generation during the day, supplement any shortfall of PV supply with battery discharge later in the day, and consume entirely off the battery after sunset. In other words, these households with integrated solar and battery systems will behave like an energy island, operating the battery solely for their convenience.

This leaves little or no battery charge to discharge to the grid during times of system peak demand. While it does reduce the household's demand from the grid at peak times, it is assumed to conserve any surplus battery charge for later rather than export surplus energy to help reduce system peak demand. Figure 6 shows that, during times of solar irradiance, the household is meeting their energy needs off the PV system, and then consuming from the battery when the sun goes down. At time of maximum grid demand, which is a

[46] For more information, see https://virtualpowerplant.sa.gov.au/.

[47] First movers of battery technology currently purchase batteries larger than their daily household needs.

few hours later than the household's peak demand due to rooftop PV, the average household with air-conditioners and basic appliances would have demand of approximately 2 kW.

2.2.3 Electric vehicles

In the NEM, approximately 2,400 electric vehicles were sold in 2017, representing 0.2% of new light vehicle sales. CSIRO projects, based on this current level of uptake, and in the absence of any policy incentives, that the uptake of electric vehicles will continue to be relatively small in the next decade, with a projected 650,000 electric vehicles across the NEM in 2027-28.

At that point, electric vehicles are projected to become cost-competitive with petrol vehicles, due to the falling cost of electric vehicles and economies of scale, driving accelerated electrification of the transport sector in the last 10 years of the forecast. By 2037-38, 5.5 million residential and commercial electric vehicles NEM-wide are forecast in the Neutral scenario, based on analysis provided by CSIRO. This compares to a forecast of 4 million electric vehicles by this time in the March 2018 EFI Update, after a similar forecast in the short term.

Figure 7 shows the 20-year electric vehicle forecast for all three scenarios and compares these to the March 2018 EFI Update.

Figure 7 NEM electric vehicles annual consumption forecast, 2017-18 to 2037-38, all scenarios, compared to March 2018 EFI Update

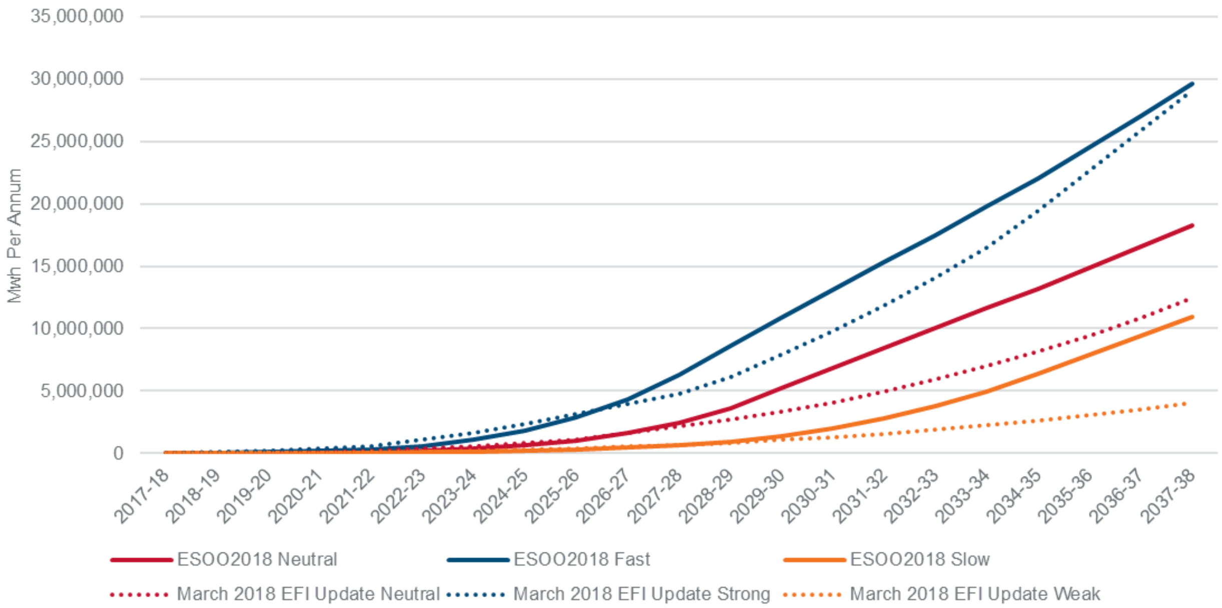
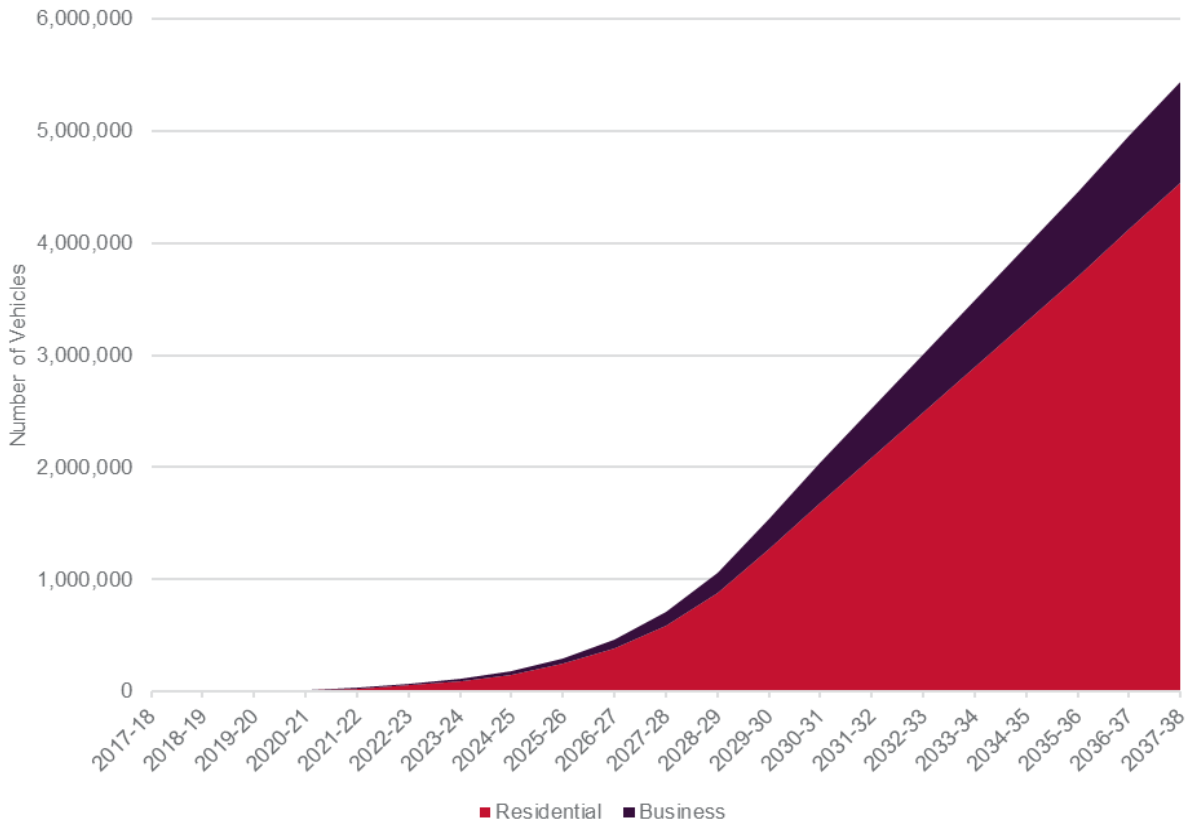


Figure 8 shows the projected uptake, split between residential and business sectors.

Figure 8 NEM forecast number of electric vehicles by sector, 2017-18 to 2037-38



The impact of electric vehicles on the daily load profile and maximum demand depends on how and when they are charged. Charging is likely to be influenced by the availability of public infrastructure, tariff structures, any energy management systems, and the driver's routine. For this 2018 ESOO, AEMO assumed a weighting of three charge profiles:

- Convenience charging – with vehicles being predominantly charged as soon drivers get home, including during peak hours.
- Smart day charging – with vehicles being predominantly charged in the middle of the day during the solar trough.
- Overnight charging – with vehicles being predominantly charged overnight, after the evening demand peak.

Implicitly, there is an assumption that at least some consumers will be incentivised to charge their electric vehicles outside the time that peak demand usually occurs. AEMO has assumed different proportions of each vehicle charging profile, depending on the scenario (see Section 1.4). These proportions change over time[48].

In the Neutral demand scenario, AEMO assumed that:

- In the first years, electric vehicles will be convenience charging, which may add to peak demand, as the example residential charge profile in Figure 9 shows. This reflects the absence of any incentive to optimise charging to manage demands on the power system.
- As penetration increases, retail tariffs or load control will start to be adopted to manage impact on peak demand. Accordingly, AEMO scales down the proportion of vehicles using convenience charging according

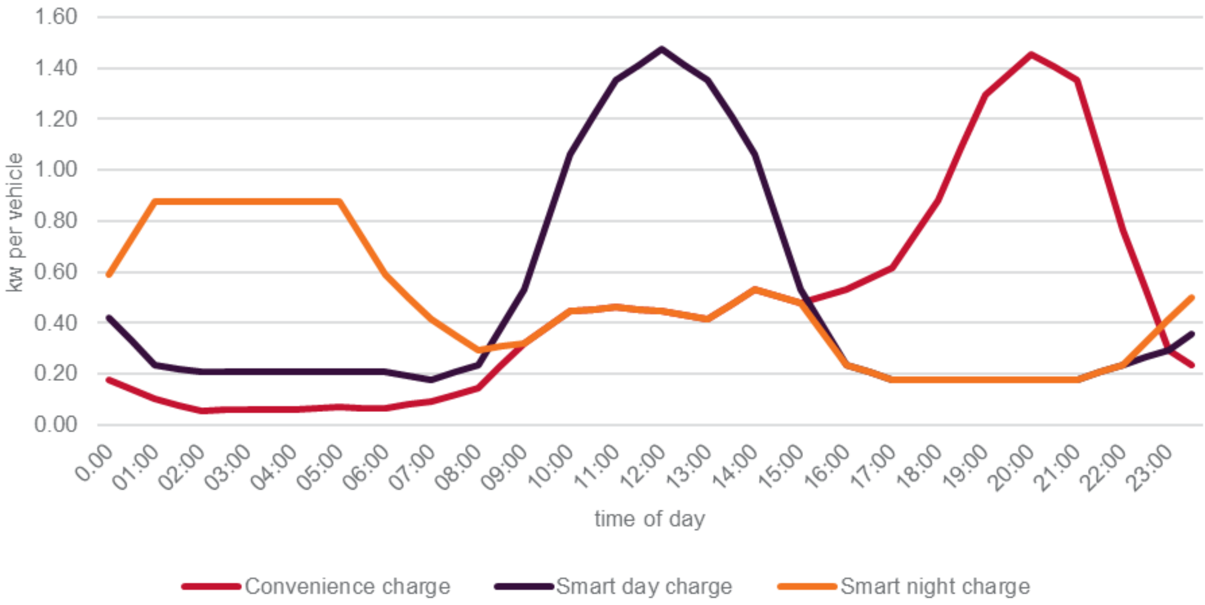
[48] The charging behaviour for residential and commercial (fleet) users of electric vehicles will continue to evolve as incentives are introduced to help manage electric vehicles effectively within the power system. These may include changing regulation and tariff offerings and introducing technology that supports smarter charging. AEMO will review and adapt the charge profiles assumed for different users and the weighting of these as more data becomes available.

to assumptions in Section 1.4, with more charging during the middle of the day or overnight rather than during grid peak demand. Vehicle-to-grid technology (electric vehicles sending power back to the grid when connected at time of peak demand) has not been considered, and would be minimal in the 10-year horizon of the ESOO).

The electric vehicle consumption forecasts used state-based vehicle activity assumptions, which influence how many vehicles are required in each region to meet travel demand. The kilometres travelled per vehicle by region changes over time (due to adoption of car/ride sharing). The charging profiles per vehicle were also adjusted for weekday/weekend differences and monthly differences based on traffic data.

The battery efficiency at the start of the forecast is approximately 1.1 kWh per km. Batteries toward the end of the forecast are assumed to become more efficient, requiring approximately 1.0 kWh per km.

Figure 9 Electric vehicle daily charge profile, residential user (weekday in February)



2.3 Energy efficiency and consumer behavioural response

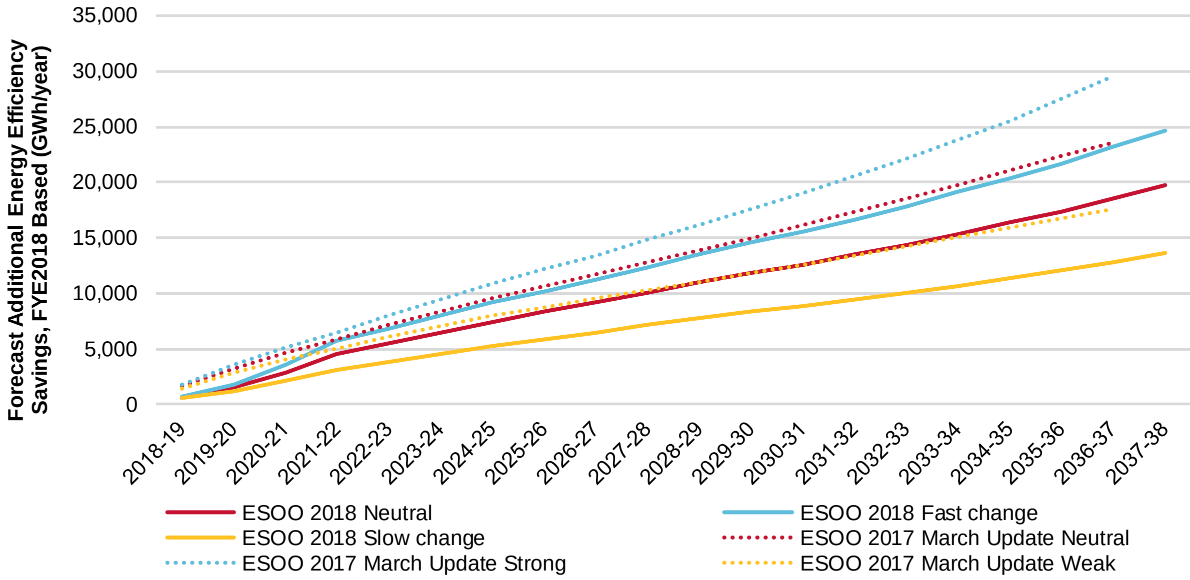
2.3.1 Energy efficiency

Projected energy efficiency savings from both the residential and business sectors are forecast to provide continued reductions in consumption due to the use of more energy efficient appliances and more energy efficient buildings, as shown in Figure 10.

Consistent with the forecasts in the March 2018 EFI Update, projected annual energy efficiency improvements are approximately 1 terawatt hour (TWh) additional savings per year in the Neutral scenario.

Improved understanding of the temperature-sensitive load for each sector has led to a downward reduction of the estimate of energy efficiency impact on maximum demand.

Figure 10 Forecast energy efficiency, 2018-19 to 2037-38, and compared to March 2018 EFI Update



AEMO engaged *Strategy. Policy. Research.*[49] to prepare an overview of current energy efficiency programs and provide a 20-year outlook[50] of energy efficiency savings for fast, moderate, and slow uptake. These outlooks are used in the Fast change, Neutral, and Slow change 2018 ESOO scenarios respectively, and include current and expected programs across:

- Energy performance requirements in the National Construction Code.
- Ratings and disclosure schemes such as National Australian Built Environment Rating System (NABERS) and Commercial Building Disclosure (CBD).
- The Equipment Energy Efficiency (E3) program of mandatory energy performance standards and/or labelling for 55 classes of appliances and equipment.
- State-based energy savings targets and related schemes in New South Wales, Victoria, and South Australia.
- The Federal Government's Energy Efficiency in Government (EEGO) Operations program.

AEMO has applied the forecast savings from the 2017-18 base year.

For the 2018 ESOO, AEMO has also used previously unavailable meter data to apportion energy efficiency savings to seasonal (cooling) parts of load. For example, in New South Wales, 4% of the total annual consumption is sensitive to hot weather, and 4% is sensitive to cool weather, with the rest of the consumption in the region being largely temperature-insensitive. Energy efficiency impacts that improve cooling and heating load productivity are now apportioned using the short-term consumption models for each region in the NEM, reflecting the current temperature-consumption profile in each region.

As consumers achieve energy savings, lowering their cost of energy, a proportion of these savings are assumed to be used towards activities that may increase consumption. Less cost-sensitive energy consumers are assumed to have a lower incentive to behave efficiently. Based on the calibration of models against metering data, this rebound effect has been estimated to be approximately 40% for both the residential and business sectors. For the business sector, this includes a correction to avoid double-counting of savings by larger industrial loads who report forecast consumption directly, net of energy efficiency initiatives.

[49] *Strategy. Policy. Research.* Energy *Efficiency Impacts on Electricity and Gas Demand to 2037-38*, June 2018. Report prepared for AEMO, published as supplementary material to the 2018 ESOO.

[50] Forecasts were produced relative to a 2001-02 baseline.

It is difficult to measure the uptake of energy efficient appliances and performance of various energy efficient schemes. This uncertainty is reflected in the three core ESOO scenarios, with greater potential savings in the Fast change scenario (25 TWh by 2037-38) and fewer in the Slow change scenario (13.5 TWh by 2037-38). Contributing to this uncertainty is a lack of available data on how the schemes have been performing, including compliance with regulation, along with the effectiveness of each scheme in the context of other policy measures. The three outlooks therefore provide a reasonable range of possible energy efficiency outcomes.

2.3.2 Fuel switching

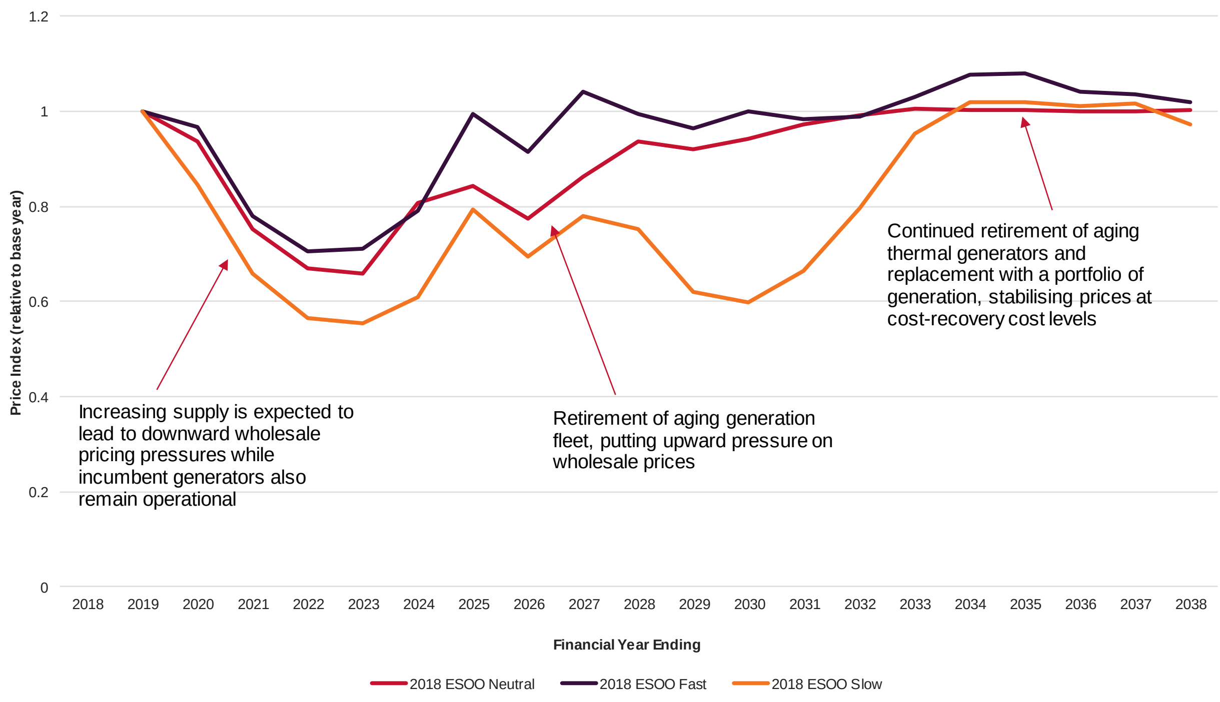
Fuel switching, in the context of the ESOO, refers to the replacement of gas with electric appliances in existing households. The proportion of households which can switch varies across NEM regions due to differing hot water and space heating appliance penetration rates, as well as gas and electricity retail price variations. Using an assessment of the economic viability of switching from gas to electric appliances, AEMO estimates that fuel switching may contribute an additional 1,306 gigawatt hours (GWh) to the 2018 ESOO Neutral forecast by 2037-38.

2.3.3 Consumer behavioural response

Price index data is used as an input into demand forecasts to model structural changes by consumers (for example, investments in rooftop PV, energy storage systems, and fuel switching) along with behavioural changes (such as how electricity devices are used or energy consumption is managed).

The estimate of price impacts on behavioural changes in consumption in the 2018 ESOO Neutral forecast is a reduction of approximately 6,000 GWh by 2037-38. This is about 50% less reduction than the modelled impact in the 2017 ESOO, reflecting updated price forecasts and consumer behaviour modelling. Figure 11 shows the wholesale price index assumed in the 2018 ESOO, which has been developed based on internal market modelling used in developing gas-powered generation (GPG) forecasts for the 2018 GSOO.

Figure 11 Forecast load weighted average Wholesale Price Index



An asymmetric approach has been adopted to estimate the price elasticity of demand (that is, the percentage change in demand for a 1% change in price). Due to actions consumers have already taken in response to higher prices (such as installing more energy efficient appliances or improving productive efficiency), demand increases in response to price reductions are assumed to be more muted than demand decreases in response to higher prices.

2.4 Weather and climate

AEMO considers the effects of future climate change in forecasting annual consumption, minimum and maximum demand. Climate change leading to warmer temperatures has the effect of reducing heating load in winter and increasing cooling load in summer. For the impact on annual consumption, see Section 3.1, and for the impact on maximum demand, see Section 3.2.

This year, AEMO collaborated with the BoM and CSIRO to improve its understanding of how climate change was impacting the full distribution of temperatures. With the help of the BoM and the CSIRO, AEMO used publicly available projections data from ClimateChangeInAustralia.gov.au to downscale and project half-hourly temperature data. The 2018 ESOO implemented the new methodology which recognises that climate change impacts minimum, average and maximum temperatures differently.

Climate change drives a greater increase in high/extreme temperature than average temperature. Following the Representative Concentration Pathway (RCP) of 4.5[51], high maximum temperatures are projected to increase by approximately 0.9⁰C over the next 20 years, while average temperatures are projected to increase by approximately 0.5⁰C over the next 20 years. Distinguishing between the increase in average temperatures and maximum temperatures may materially influence summer maximum demand from a reliability perspective.

[51] The RCP trajectories were adopted by the Intergovernmental Panel on Climate Change IPCC) in 2014. This future climate scenario assumes CO_2 concentration reaching 540 parts per million (ppm) by 2100.

3. Demand forecasts

Based on the key input drivers covered in the previous section, AEMO has forecast operational electricity consumption and maximum and minimum demand out to 2037-38. These drivers interact in ways that result in operational maximum demand growing faster than operational consumption, as discussed in this section. Region-specific trends are discussed in more detail in Appendix A2.

3.1 National Electricity Market annual consumption forecasts

Key insights

- Growth in population, GSP, and manufacturing output is forecast to continue, and with it underlying demand[52] for electricity. Underlying consumption is forecast to increase at approximately 1.3 % a year on average for the next 20 years in the Neutral scenario.
- As the outlook for the uptake of DER such as rooftop PV remains strong in the medium term, operational consumption (grid-supplied energy) across the NEM is forecast to remain relatively flat in the next 10 years.
  - Over the short term (0-5 years), projected operational consumption in 2022-23 across the NEM is 183 TWh, compared to 183.5 TWh in 2017-18. Forecast strong rooftop PV uptake during this period, of approximately 4.2 TWh new annual generation (or a 50% increase from current installed capacity), is projected to offset forecast growth from expected increases in population and economic activity.
  - In the medium term (5-10 years), slight growth in operational consumption is forecast, from 183 TWh in 2022-23 to 188 TWh in 2027-28 (0.55% annual average growth), as the projected PV growth rate moderates.
- Longer term, the forecast rapid electric vehicle uptake lifts growth in operational consumption:
  - In the long term (10-20 years), the highest increase in consumption over the 20-year outlook is forecast, with operational electricity consumption projected to grow from 188 TWh in 2027-18 to 208 TWh in 2037-38 (1.12% annual average growth). This is largely due to approximately 4.7 million projected additional electric vehicles in this period contributing to a total of 16 TWh forecast increase in consumption.

To separate and project the range of complex dynamics that are important to electricity consumption patterns, AEMO electricity consumption forecasts are based on a mix of 'bottom-up' stock or capacity-based models and top-down econometric models, calibrated in both cases against the most recent meter data.

Forecasts are for delivered demand in the residential and business sectors (business includes industrial and commercial users), and these sector forecasts, adding transmission and distribution losses and offset by non-scheduled generation, are combined to provide the total NEM operational consumption forecast. Sections 3.1.1 and 3.1.2 provide details on sector demand forecasts.

[52] Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as rooftop PV.

Figure 12 shows:

- Actual operational consumption, and the impact of rooftop PV, since 2006-07.
- Forecast operational consumption for the Neutral scenario, by sector, showing the relatively large size of business consumption in the total.
- The factors projected to reduce consumption from the grid from the level it would otherwise have been forecast to reach – such as DER (primarily rooftop PV) and energy efficiency.

The figure also shows the total Neutral scenario forecast from the March 2018 EFI Update. The main difference between the two forecasts is that, in the second decade of the outlook period (so beyond the ESOO's 10-year outlook period), demand for charging of electric vehicles is now forecast to be greater than had earlier been expected.

Figure 12 NEM electricity consumption, actual and forecast, 2006-07 to 2037-38, Neutral scenario

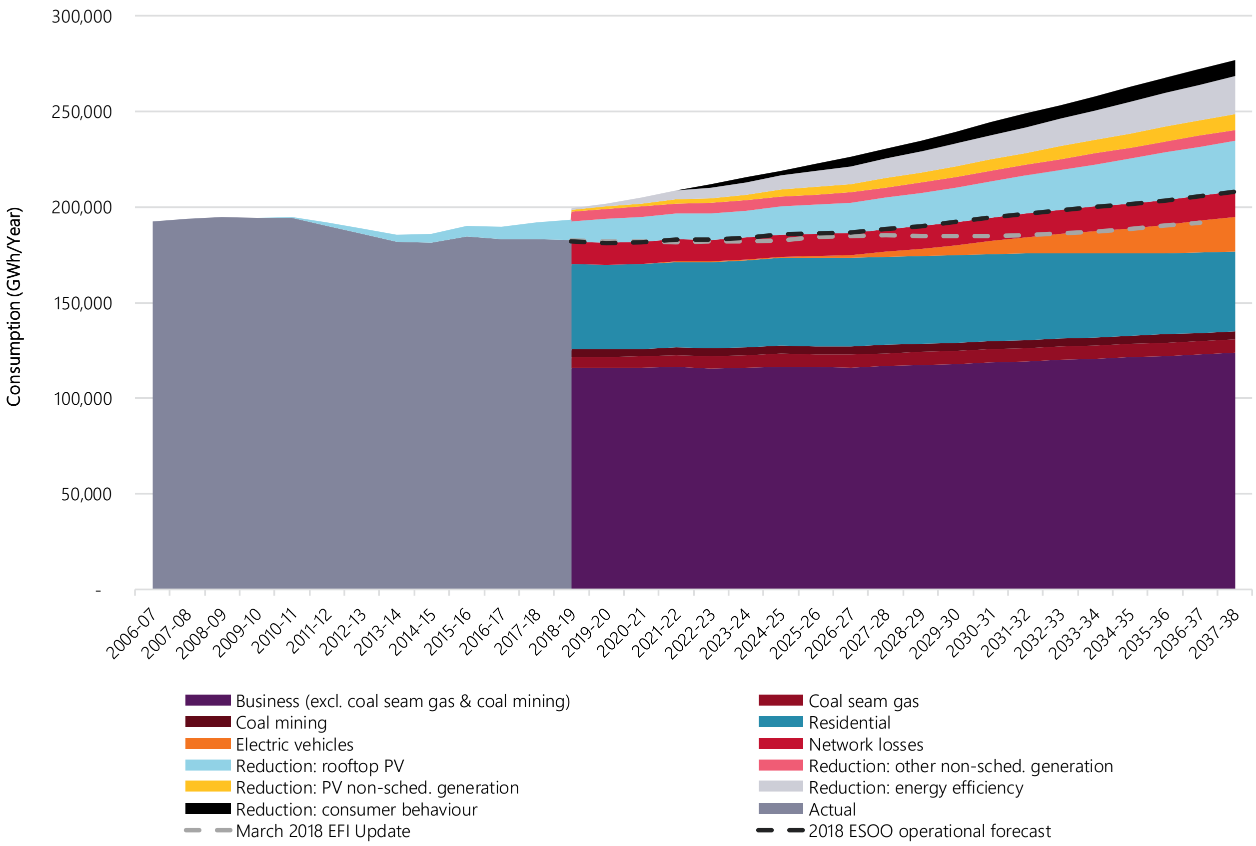
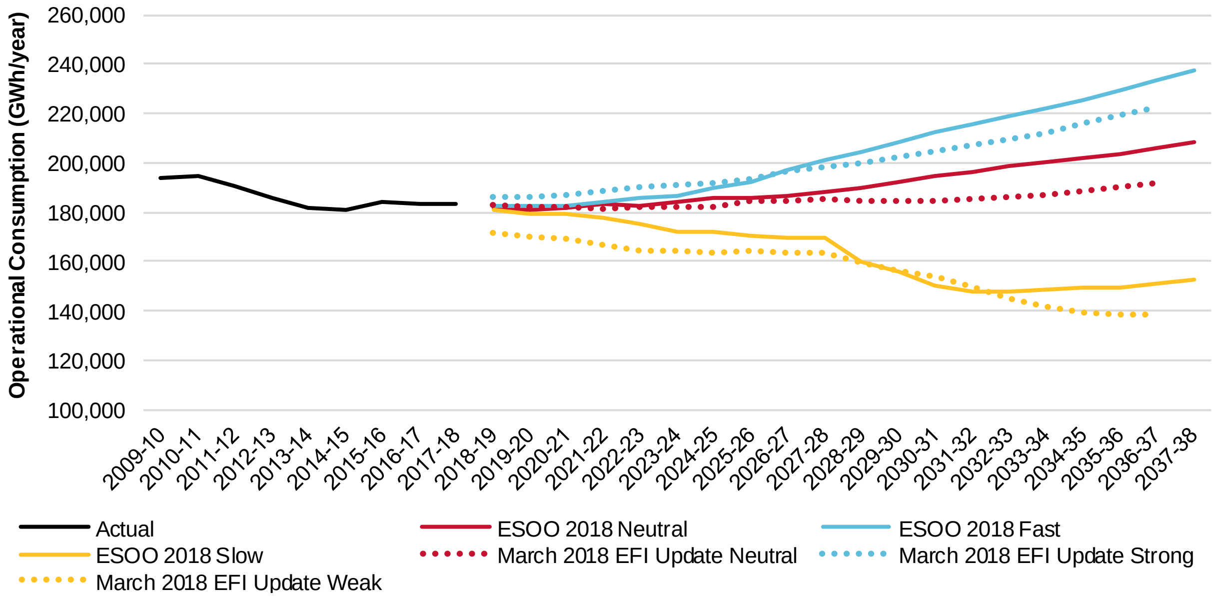


Figure 13 shows the consumption forecasts for the three 2018 ESOO scenarios, to illustrate the spread of plausible operational consumption outcomes under different assumptions, and compares these to the forecasts in the March 2018 EFI Update.

Figure 13 NEM operational consumption, actual and forecast, all scenarios, 2009-10 to 2036-37, and compared to March 2018 EFI Update



3.1.1 Residential sector forecasts

Key insights

- In the short term (0-5 years), underlying household annual consumption is projected to rise due to growth from new connections (population), an increasing number of appliances, and gas to electric appliance switching. This growth in electricity usage is not forecast to translate into significant usage growth from grid-based generators, as it is projected to be offset by a sustained rooftop PV uptake (see Section 2.2.1) and the use of more energy-efficient appliances. This results in forecast marginal growth in delivered electricity to residential consumers during this period at an annual average rate of approximately 0.4%.
- In the medium term (5-10 years) delivered electricity to residential consumers is expected to increase to a greater extent, as the PV installation rate is forecast to decline, and electric vehicles are forecast to begin emerging as a significant sector in the market. Delivered consumption over the five-year period is forecast to increase at an annual average rate of approximately 1.3%, commensurate with population growth projections.
- In the long term (10-20 years, so beyond the ESOO's 10-year outlook period) the number of electric vehicles is expected to accelerate, increasing underlying demand for electricity. Growth in residential rooftop PV is projected to increase again, offsetting some underlying demand growth. The net result is a projected annual average residential delivered consumption growth rate of 1.5%.

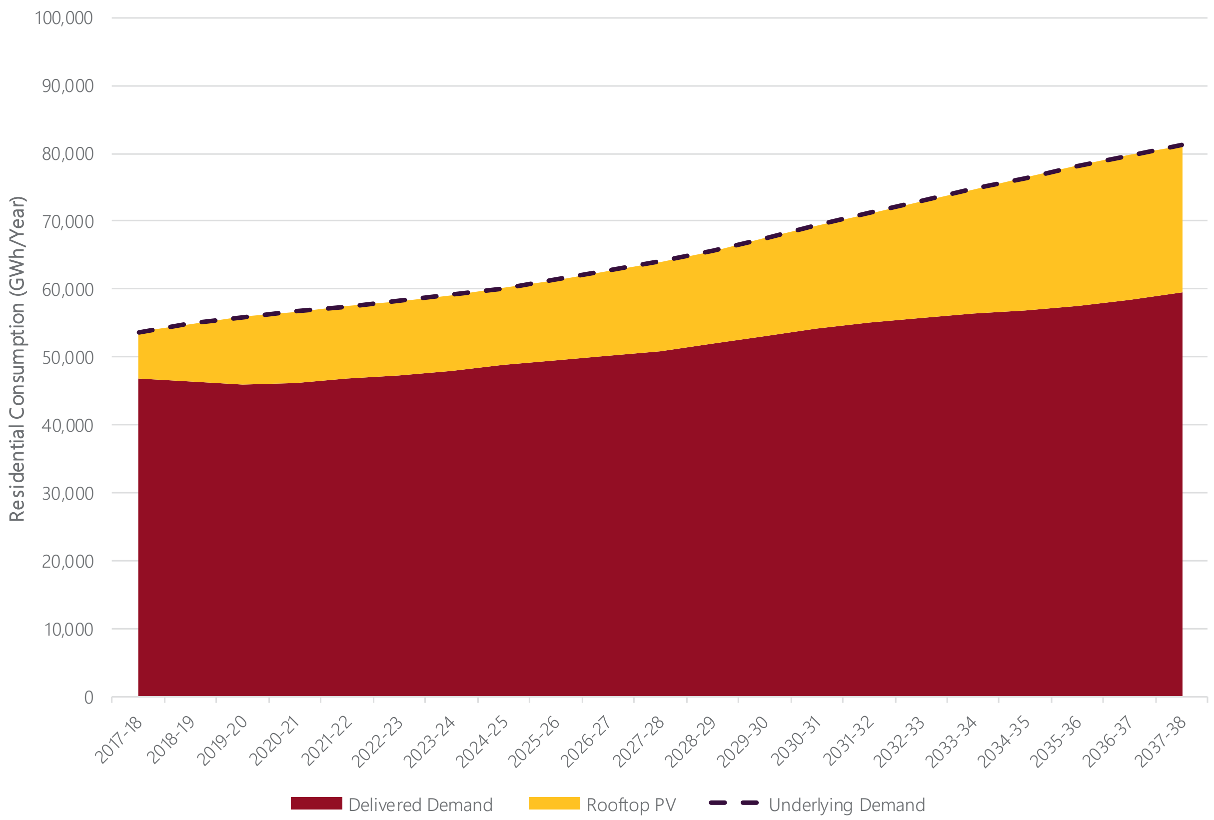
AEMO has developed residential forecasts using forward estimates of weather-adjusted consumption on a per connection basis. The forecast number of new connections therefore drives the growth trajectory, subject to other influences (such as changing consumer behaviours in response to pricing stimuli, new appliance uptake, appliance fuel switching, and broader energy efficiency impacts).

The overall 2018 ESOO forecast outlines a higher delivered residential consumption forecast than in the March 2018 EFI Update. With improved data inputs, the projected upward shift in delivered electricity to consumers from the grid reflects higher forecasts of dwelling growth and electric vehicle uptake, as well as lower projections for rooftop PV in the medium term and less consumer price response (see Section 2.3).

The net projected impact of climate change on residential electricity forecasts is that it reduces consumption, as the reduced need for heating load over milder winters more than offsets the increased consumption for cooling load during summer. Queensland is the exception to this projection, because residential consumers in this region generally use more electricity in the hotter months than they do in winter, with that trend expected to increase as average temperatures increase.

Figure 14 shows the Neutral scenario forecast, highlighting how rooftop PV is forecast to meet some expected increases in underlying demand, leading to moderate growth in delivered demand.

Figure 14 Forecast underlying residential consumption (including electric vehicles), delivered (sourced from scheduled and embedded generators) and sourced from rooftop PV, 2017-18 to 2037-38

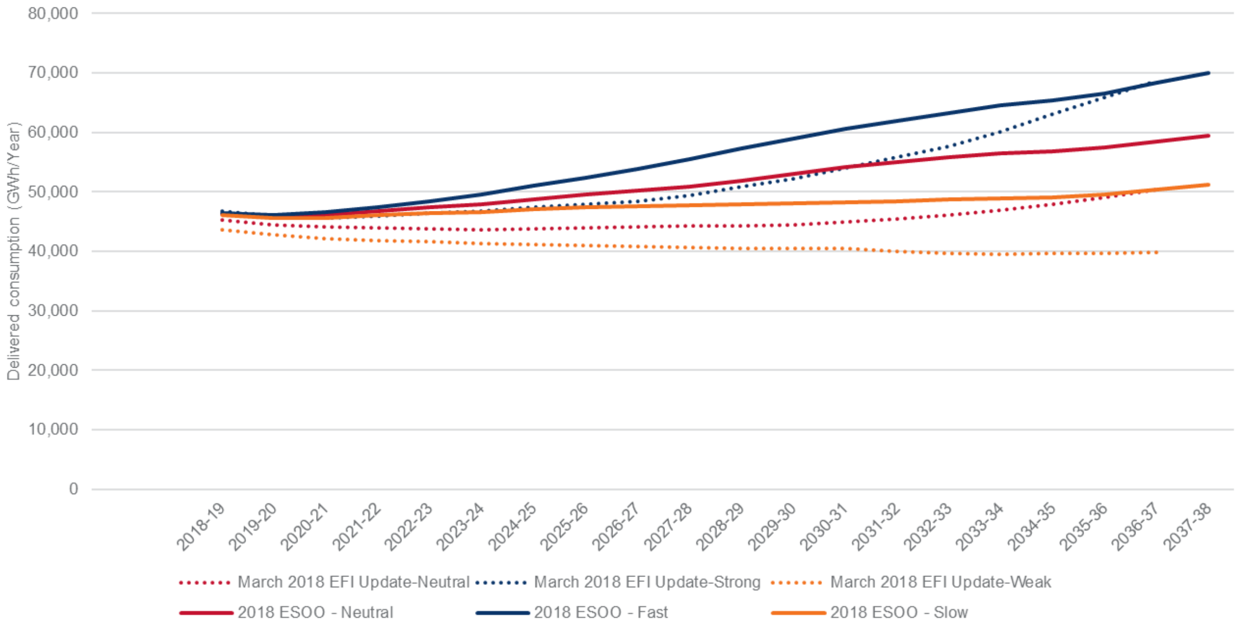


Under the Fast change scenario, driven by projected stronger growth in new dwellings and more rapid forecast uptake of electric vehicles, residential annual delivered consumption NEM-wide is forecast to go up by half over the 20-year forecast (or 2.5% annual average).

In contrast, the Slow change forecast trajectory reflects a lower forecast for new dwellings, electric vehicles, energy-efficiency impacts, and less residential consumption in response to retail price rises, compared to the Neutral pathway. Under the Slow change scenario, annual delivered consumption growth remains relatively flat in the short term, followed by a slight increase, mainly in the latter half of the outlook period. This results in growth of 11 % (or 0.5% annual average) over the 20-year forecast.

Figure 15 shows the range of projected residential consumption outcomes across the three core scenarios, and a comparison to the March 2018 EFI Update.

Figure 15 NEM delivered residential electricity consumption forecast, all scenarios, 2018-19 to 2037-38, and compared to the March 2018 EFI Update



3.1.2 Business sector forecasts

Key insights

- Over the 20-year forecast, underlying demand from the business sector is projected to continue growing at an annual average rate of approximately 0.5%, while delivered consumption is forecast to grow more slowly.
- In the short term (0-5 years) Neutral scenario, although electricity consumption is projected to grow as forecast economic conditions improve in many sectors, business rooftop PV is also forecast to grow, contributing to only marginal growth in delivered electricity to business consumers during this period (approximately 0.2% annual average).
- In the medium term (5-10 years) Neutral scenario, approximately 0.4% annual average growth in delivered electricity is forecast, due to a combination of higher projected GSP[53] and HDI. Higher HDI translates to more consumer spending on goods and services, which increases business consumption. Commercial electric vehicles are also being forecast to have a growing impact on consumption.
- In the long-term (10-20 years) Neutral scenario, these drivers are projected to result in further growth in delivered electricity to business consumers (approximately 0.6% annual average).
- Although the current economic outlook for businesses has stabilised in the Neutral scenario, there remains significant downside risk if electricity prices rise or economic conditions change, as projected in the Slow change scenario.

The business sector includes industrial and commercial users. Recognising different drivers affecting forecasts, the business sector is further split into:

[53] These economic projections were developed by an economic consultant, according to AEMO's scenario requirements, for the purpose of producing the electricity demand forecasts for this ESOO. The index data series of the economic forecasts are available on AEMO's forecasting data portal, at http://forecasting.aemo.com.au.

- Coal seam gas (CSG) – electricity consumption associated with the production of LNG for export.
- Coal mining – consumers mainly engaged in open-cut or underground mining of black or brown coal.
- Manufacturing – traditional manufacturing business sectors.
- Other business – business consumers not covered by the categories above, predominantly services businesses.

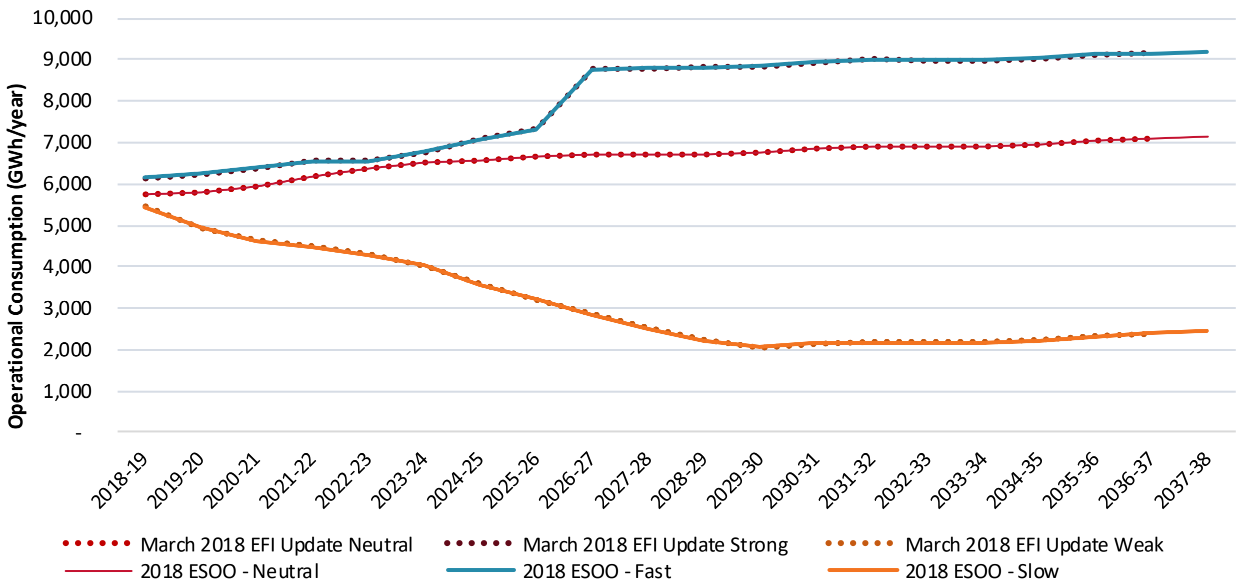
Coal seam gas sector forecasts

Electricity forecasts for the CSG sector, shown in Figure 16, reflect the grid-supplied electricity consumed by the east coast LNG consortia. This is predominantly used in the extraction process for CSG production, so the electricity projection closely follows CSG production trend drivers[54]:

- In the short term (0-5 years), electricity consumption forecasts are adjusted to align with the CSG production forecasts provided to AEMO by the LNG consortia. In the long term (6-20 years), electricity consumption is commensurate with rises in forecast CSG production as LNG projects ramp to full production, largely motivated by stronger demand for LNG in Asia.
- The Fast change scenario has an earlier increase in electricity usage than the Neutral scenario, as it assumed LNG companies will be more aggressive in debottlenecking LNG facilities, resulting in more CSG being produced to fill LNG trains. In the longer term, the Fast change scenario considers the possibility of an additional LNG export facility from 2025, ramping up to full capacity export by 2027 and sustained for the remaining forecast period[55]. While there is no current prospect for future LNG facilities, this increase serves in the modelling as a proxy for new electricity-intensive load in Queensland. It does not reflect any known investment under consideration.
- The Slow change scenario assumes a reduced incentive for further drilling beyond existing well production. It follows the production profile of existing wells, declining to minimum production levels by 2029.

There are no changes to these forecasts compared with the March 2018 EFI Update.

Figure 16 NEM delivered CSG electricity consumption forecast, all scenarios, 2018-19 to 2037-38



[54] The CSG forecasts that underpin the electricity forecasts in this 2018 ESOO were developed considering stakeholder guidance and long-term forecasts from Lewis Grey Advisory (LGA). For further details including grid-sourced electricity consumption to CSG production estimates, please see the Lewis Grey Advisory (LGA) report on AEMO's website at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

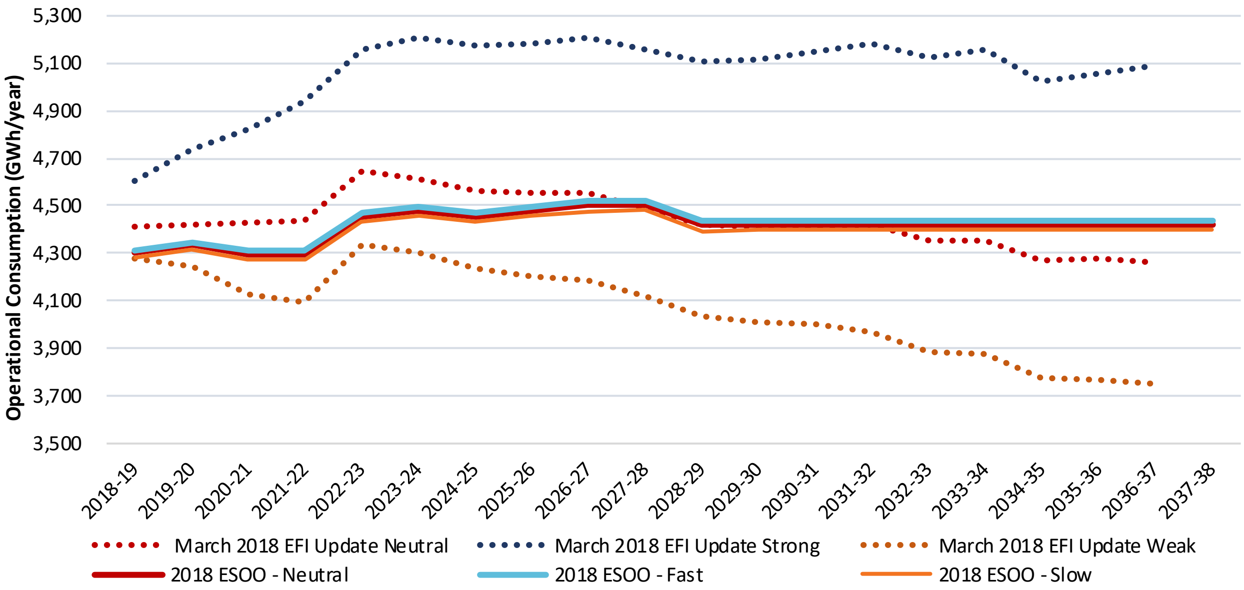
[55] AEMO includes this forecast to reflect possible increases in electricity consumption that can occur under the assumptions in the Fast change scenario.

Coal mining sector forecasts

Figure 17 shows the projected outcomes in the coal mining sector across the three core scenarios, and a comparison to the March 2018 EFI Update.

Electricity consumption in the coal mining sector (located almost entirely in New South Wales and Queensland) is forecast to remain relatively unchanged for the next 20 years. According to the Office of the Chief Economist forecasts[56], contractual obligations and the higher quality thermal and metallurgical coal supplied from Australia is not projected to reduce over the forecast period and the outlook for metallurgical coal is projected to remain strong.

Figure 17 NEM delivered coal electricity consumption forecast, all scenarios, 2018-19 to 2037-38, and compared to the March 2018 EFI Update



Manufacturing sector forecasts

Electricity consumption for the Manufacturing sector, which is largely export-facing, has declined for the last decade (by approximately 2% a year), attributed to a challenging economic environment as well as recent electricity price rises.

Manufacturing businesses have reduced their consumption by actions including energy efficiency programs, technological improvements, automation upgrades, and using import substitution for raw materials. Although there have been improvements in global and domestic economic conditions, with GSP projected to grow over the 20-year outlook, there are still some businesses which continue to face price pressures. Risks have generally eased slightly due to a more favourable price outlook, though some uncertainties remain around the long-term sustainability of businesses facing high energy bills, and this uncertainty is reflected in the Slow change scenario.

Figure 18 shows the range of projected outcomes in the manufacturing sector across the three core scenarios, and a comparison to the March 2018 EFI Update.

In the Neutral scenario, the forecast trend is for modest increases in delivered electricity consumption for the Manufacturing sector over the 20-year outlook, with an average annual increase of 0.6% (slightly higher than the previous forecast growth rate of 0.4%).

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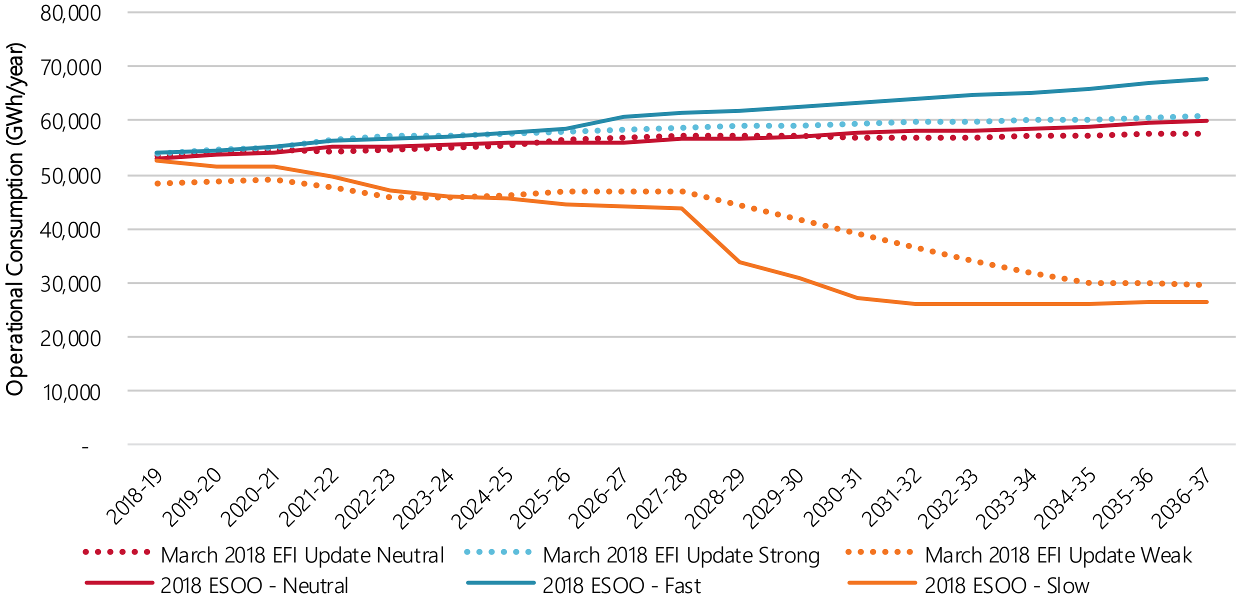
[56] Office of the Chief Economist, June 2018, https://publications.industry.gov.au/publications/resourcesandenergyquarterlyjune2018/index.html.

The Fast change scenario forecast trend is similar to the Neutral scenario, although most of the forecast consumption growth is over the medium term, driven mainly by projected growth in GSP.

Under the Slow change scenario, consumption is forecast to fall, especially in the long term. This scenario's assumptions include slower economic growth, reduced consumer confidence, and sluggish export markets, combined with input price pressures from electricity, which place more loads at risk of closure. These risks increase over the 20-year outlook, due to persisting weak economic conditions eroding business resilience.

Figure 18 NEM delivered manufacturing electricity consumption forecast, all scenarios, 2018-19 to 2037-38, and compared to the March 2018 EFI Update



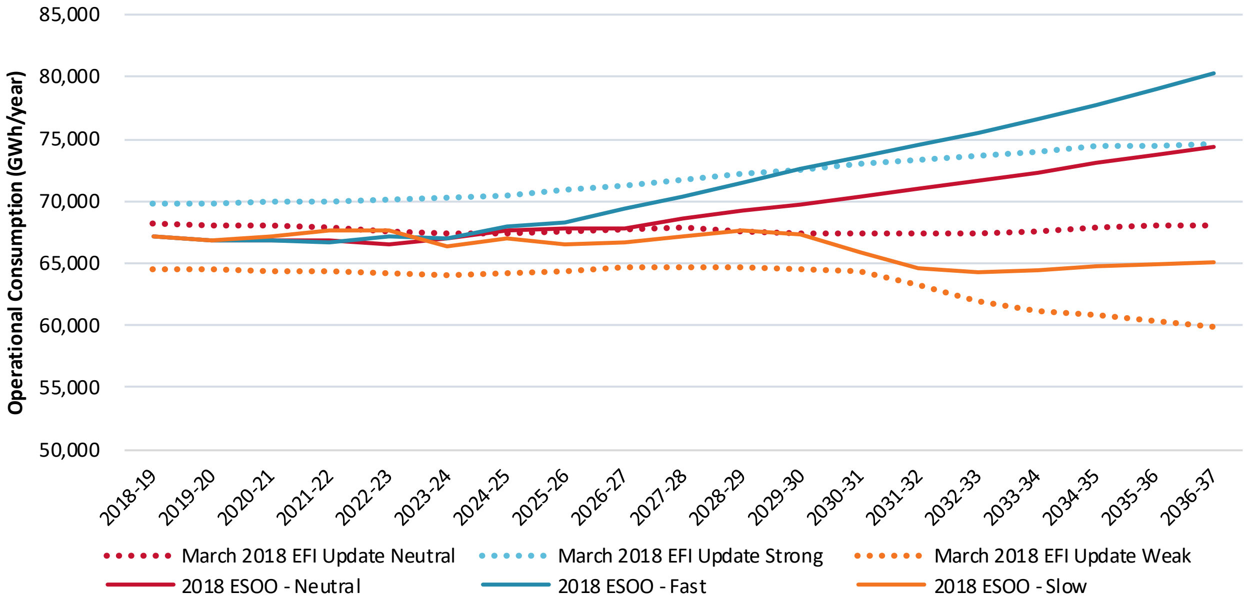
Other business sector forecasts

The Other business sector group consists of services businesses, such as finance services, education, health care, telecommunications, transport, and construction services.

In the short-term Neutral scenario, delivered electricity consumption for the Other business sector is forecast to remain relatively flat, due to uptake of small-scale embedded technologies, and energy efficiency and consumer behavioural responses.

The Fast change scenario shows greater long-term demand growth, due to higher growth in HDI and population, while the Slow change scenario shows decreased electricity consumption due to a higher price forecast, with more loads being at risk of closure.

Figure 19 NEM delivered Other business electricity consumption forecast, all scenarios, 2018-19 to 2037-38, and compared to the March 2018 EFI Update



3.2 Maximum demand and minimum demand

Key insights

- Maximum operational demand is expected to peak later in the day due to growth in installed rooftop PV capacity, until it reaches a point in the day where, more often than not, the generation from the installed PV capacity no longer offsets growth drivers.
- Maximum demand (10% POE) is forecast to be relatively stable in most regions over the next five years, then to grow by approximately 1% annual average to 2037-38, as rooftop PV generation is projected to stop offsetting the impact of growth in GSP, connections, and electric vehicles, and declining prices. This growth turning point occurs about two years earlier than previously projected, due to the record growth in PV installations currently observed.
- Maximum operational demand (10% POE) currently occurs, and is expected to continue occurring, in summer (driven by cooling load) in all regions but Tasmania, where the peak is in winter (driven by heating load). The relatively less extreme maximum operational demand at a 50% POE may become winter-peaking in New South Wales by the end of the forecast period.
- Minimum demand in South Australia and Tasmania was experienced at midday in 2017-18. Minimum demand in all other regions currently occurs overnight or early morning. Under 90% POE minimum demand conditions, New South Wales, Victoria, and Queensland are expected to experience a midday minimum as early as next year, due to the high uptake of rooftop PV capacity.
- Both maximum and minimum demand are measured at the NEM region level. Because the peaks and lowest demands occur at different times in different regions, they cannot be added together and there is no NEM-wide coincident maximum or minimum against which supply is assessed.

3.2.1 Maximum demand

Maximum demand is forecast to continue to shift later in the day in all regions except South Australia and Tasmania.

- South Australia already experienced its maximum at around 8.00 pm in the summer of 2017-18 and, on the balance of probability, this is expected to continue occurring around this time.
- Tasmania, because it is winter peaking, peaks after sunset, driven by heating load.

The forecast shift of maximum demand to later in the day over the next 10 years would result in a declining contribution of PV generation. This is projected to limit the ability of additional rooftop PV installations to offset other demand drivers, such as connections growth and appliance uptake[57].

In the short term (0-5 years), compared to the March 2018 EFI Update:

- The outlook for maximum operational demand[58] sent out (10% POE) is slightly higher for Victoria over the next couple of years (about 50 MW to 100 MW higher), while for New South Wales and Queensland (including CSG) the ESOO 2018 forecast is lower, due to the increased uptake of rooftop PV in the last 12 months, which is expected to continue in the short term.
- Maximum demand forecasts for Tasmania are also lower in the short term, due to forecast reductions in large industrial load demand.
- South Australia's forecast maximum demand is higher. This is attributed partly to growth drivers for business load, and also the expectation that, on the balance of probability, maximum demand is already peaking too late in the day for rooftop PV to have a substantial impact offsetting growth in grid demand.

Over the 5-10-year period, maximum demand begins to grow faster than projected in the March 2018 EFI Update. Then, in the 10-20-year horizon, forecast maximum demand is higher for all regions. A number of growth drivers lead to higher demand in this forecast relative to March 2018 EFI Update:

- The 2018 ESOO has improved the application of energy efficiency, as discussed in Section 2.3.1. With the improvement to modelling energy efficiency, cooling appliances are projected to be less efficient at times of grid maximum, relative to the March 2018 EFI Update. This has a far greater impact on maximum demand than on annual consumption. At an annual level, cooling load represents approximately 4% of total consumption. However, on a hot day, cooling load represents approximately 30-40% of demand.
- The new forecasts include higher projected rates of new electricity connections and lower projected uptake of behind-the-meter batteries and rooftop PV in the medium term, as discussed in Section 2).
- Electric vehicles are forecast to contribute to about 800 MW to 1,200 MW of maximum demand in 2038, depending on the region. In the Neutral scenario, AEMO assumed that 50% of electric vehicles in 2037-38 would be charging according to a convenience charge profile (see Section 2.2.3), while the other 25% of vehicles would follow a day charge profile and the remainder overnight. The March 2018 EFI Update (which had a flat charge profile outside of overnight periods), and now the 2018 ESOO, are the first AEMO maximum demand forecasts to assume a certain amount of electric vehicle charging during peak demand times, due to modelling improvements discussed in Section 1. New incentives would need to be put in place to discourage charging during peak periods.
- As mentioned in Section 2.4, AEMO collaborated with the BoM to better capture how maximum temperatures were increasing due to climate change. This adds approximately 60 MW to forecast maximum demand in Victoria, and 100 MW in New South Wales, by 2037-38. AEMO continues to collaborate with the BoM and CSIRO to improve the way climate change is captured in forecasts.
- Included in the maximum demand forecast is a percentage of behind-the-meter battery operating as a virtual power plant. In the Neutral scenario, 28% of batteries are aggregated in 2037-38 as a dispatchable virtual power plant. The operational demand is lowered based on the assumed contribution from non-aggregated battery only, and the virtual power plant is explicitly modelled as a dispatchable supply option. Because of this improvement, the 2018 ESOO demand forecasts are not directly comparable to

[57] To the extent gas heating is replaced by electric heating.

[58] Operational refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Operational demand is reported by region and is not cumulative across the NEM. For more on definitions, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Operational-Consumption-definition---2016-update.pdf.

those in the March 2018 EFI Update. This inclusion accounts for approximately 30-40 MW of the apparent increase in this forecast compared to the March 2018 EFI Update in summer maximum demand forecasts in 2037-38.

Table 5 shows maximum summer demand for 10% POE and 50% POE. The table shows that 1-in-10-year demand events are about 10% higher than 1-in-2-year demand events, although this difference varies slightly depending on the region. New South Wales, Victoria, and South Australia have the highest variability between 10% POE and 50% POE, because in these regions residential demand (which tends to be more weather-sensitive and peaky) makes up a larger proportion of the load. Queensland and Tasmanian demand is typically less sensitive to weather at peak times, because the regions experience relatively less variability in temperatures and have proportionally higher demand from large industrial loads.

Table 6 shows the maximum winter demand for the same POEs. Tasmania has its annual peak in winter, driven by heating load. A comparison with Table 5 shows that, under a normal maximum operational demand year (at 50% POE), New South Wales may be winter-peaking by the end of the forecast.

Table 5 Forecast maximum operational demand (summer) by region, Neutral scenario (MW)

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE
2019	14,024	12,366	9,067	8,533	3,176	2,901	1,371	1,344	9,764	8,983
2023	14,260	12,442	9,091	8,626	3,228	2,951	1,390	1,359	9,959	9,249
2028	15,062	13,172	9,287	8,857	3,309	3,004	1,398	1,367	10,455	9,679
2038	16,965	14,870	10,258	9,835	3,639	3,305	1,483	1,450	12,126	11,371

Table 6 Forecast maximum operational demand (winter) by region, Neutral scenario (MW)

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE	10% POE	50% POE
2019	12,364	11,820	7,548	7,375	2,452	2,358	1,718	1,675	7,808	7,573
2023	12,644	12,073	7,855	7,663	2,519	2,432	1,729	1,692	8,114	7,861
2028	13,550	12,970	8,242	8,047	2,566	2,483	1,742	1,703	8,552	8,323
2038	16,250	15,628	9,427	9,185	2,893	2,811	1,859	1,825	10,669	10,378

3.2.2 Minimum demand

Minimum demand is forecast to decline rapidly over the next five years, due to projected high rooftop PV uptake (discussed in Section 2.2.1).

Due to the increase of rooftop PV, all regions are expected to experience minimum demand in the middle of the day within the next year or two (excluding South Australia, which has been experiencing day minima since 2012). This is about two years earlier than previously projected.

Forecasting the minimum demand in regions is important to understanding security risks. The forecast reduction in minimum operational demand in all NEM regions over the outlook period would result in more periods where there is little generation supplied by centrally managed generators to control the system. It may also reduce maintenance windows, as synchronous generation may be directed online to manage system strength[59].

The highest short-term risk is in South Australia, where the minimum demand is forecast to fall to 70 MW by 2021-22 and become negative by 2023-24 for 90% POE minimum demand[60], one year earlier than forecast in the March 2018 EFI Update. The ISP recommends the construction of the RiverLink interconnector and increased coordination of DER in South Australia, which would help mitigate this risk.

Table 7 Forecast minimum operational demand (summer) by region, Neutral scenario (MW)

	New South Wales		Queensland (inc CSG)		South Australia		Tasmania		Victoria	
	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE
2019	4,489	4,832	3,949	4,271	250	341	832	847	2,460	2,691
2023	3,808	4,213	3,433	3,803	21	123	787	810	1,950	2,198
2028	3,790	4,241	2,740	3,178	-244	-148	708	730	1,763	2,014
2038	3,746	4,329	687	1,313	-805	-691	661	686	1,050	1,347

Table 8 Forecast minimum operational demand (winter) by region, Neutral scenario (MW)

	New South Wales		Queensland (inc CSG)		South Australia		Tasmania		Victoria	
	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE
2019	5,673	5,848	3,573	3,669	494	618	927	950	2,921	3,479
2023	5,205	5,472	2,992	3,101	297	447	926	961	2,617	3,081
2028	5,310	5,597	2,324	2,467	87	227	881	949	2,586	3,065
2038	5,757	6,113	603	787	-298	-130	885	961	2,594	3,103

[59] System strength refers to a suite of interrelated factors that together contribute to power system stability, or the ability of the power system to return to stable operating conditions following a physical disturbance. For more, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[60] Minimum demand is expected to become negative due to the high penetration of rooftop PV more than satisfying demand during the day.

4. Supply forecasts

In the 12 months since the 2017 ESOO, an abundance of new wind and solar generation projects entering the market has seen the total installed capacity of existing generation rise by almost 3 GW, to a total of 49.99 GW (or 49,990 MW).

As of 1 July 2018, over 5.2 GW of further semi-scheduled renewable generation (mostly over 30 MW in size) is classified as committed and/or under construction. In the last quarter alone, approximately 2.7 GW of additional wind and solar projects have reached committed status, roughly half in Victoria. The level of committed renewable generation is likely to be sufficient to meet the legislated national Large-scale Renewable Energy Target (LRET).

There is also a substantial pipeline of proposed new generation under various stages of development. The most recent AEMO Generation Information update[61] reports a total of 49.46 GW (49,462 MW) of new generation proposed to be developed across the NEM, along with the progress of their development. Most of the proposed capacity has been announced as renewable energy projects – wind, solar, or a hybrid of both – and some projects also nominate additional storage capacity to be developed in combination. Nearly 1,700 MW of utility-scale storage has been publicly announced.

There has also been renewed development interest in flexible GPG to maintain reliability and provide backup during times of renewable generation troughs. For New South Wales, at least 1,000 MW of GPG projects are publicly announced, and in South Australia, the 210 MW reciprocating engine (gas-fired) Barker Inlet Power Station is committed for operation by August 2019.

Meanwhile, the existing thermal generation fleet is aging, and analysis of historical unplanned generation outages has highlighted a gradual deterioration in plant reliability in aggregate, most evident over the past three years. Market participants have announced retirement of over 2,300 MW of dispatchable generation within the next 10 years.

This section:

- Summarises the generation development modelled in the core ESOO scenarios.
- Illustrates the differences in generation and transmission development between the ISP sensitivities and ESOO scenarios.
- Provides an overview of the modelling of the transmission network, and the approach used to model intermittent and dispatchable generation.

4.1 Generation changes in the ESOO

The core ESOO scenarios include only existing and new generation that meet AEMO's commitment criteria. These criteria are used to consistently assess whether a project has made a formal commitment to construct, and includes projects already under construction.

The 2018 ESOO includes all generation that was existing or committed in the Generation Information update published 31 July 2018.

[61] 31 July 2018 update, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

In total, ESOO modelling included over 5.6 GW of committed generation and storage capacity, and existing generation upgrades. Most of these projects are additional to what was considered committed in the 2017 ESOO.

Table 9 summarises committed generation developments, augmentations, retirements, and withdrawals.

Table 9 Generation capacity developments in the 2018 ESOO (nameplate capacity, MW)

	New South Wales	Queensland	South Australia	Tasmania	Victoria	NEM
Wind generation	339	574	251	256	1,507	2,927
Solar generation	278	1,422	218	-	397	2,315
Gas-powered generation (GPG)	-	-	210	-	-	210
Generator upgrades (summer capacity)	100	-	-	-	-	100
Battery storage	-	2	-	-	75	77
Withdrawals (summer capacity)	-	-	-	208	-	208
Announced retirements (summer capacity)	1,800	34	480	-	-	2,314

The generation withdrawals and retirements shown above include the following, based on information provided by the relevant generators:

- Torrens A Power Station (480 MW, South Australia) will retire, with two units retiring in 2019, and the other two units retiring in 2020 and 2021[62]. The station is to be partially replaced by the Barker Inlet Power Station (210 MW, South Australia) which will commence operation in 2019.
- Liddell Power Station (1,800 MW summer capacity, New South Wales) will retire in 2022.
- Mackay Gas Turbine (34 MW, Queensland) will retire in 2021[63].
- Tamar Valley combined-cycle gas turbine (CCGT) (208 MW, Tasmania) is unavailable, based on advice from Hydro Tasmania. While not modelled to return to service in this ESOO, Hydro Tasmania has advised that this power station is available for operation with less than three months' notice.

4.2 Generation development in the ISP

The ESOO's purpose is to inform the industry about the market, including potential future supply gaps and emerging development needs, to allow a market response. It therefore assesses whether existing and committed supply is likely to meet forecast demand across the modelling period and identifies future development needs.

The ISP considers the development of a portfolio of resources that could meet this need at lowest cost, with a focus on any associated transmission developments and the potential role of renewable energy zones (REZs) in meeting future needs. The ISP therefore incorporates projected development of generation assets, beyond those included in the core ESOO scenarios (those which exist or currently meet commitment criteria).

[62] For more information, see https://www.agl.com.au/about-agl/how-we-source-energy/agl-torrens.

[63] Based on advice from Stanwell Corporation. See 31 July 2018 Update on AEMO"s Generation Information web page, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 20 highlights the differences between the ISP generation outlook and the committed development over the next 10 years used in the 2018 ESOO analysis, summarising the increasing level of installed capacity from newly committed wind and solar generators in each outlook over time. It shows that committed development in the ESOO plateaus from 2020-21, since projects planned for commissioning beyond that point typically do not meet all commitment criteria this far in advance. In contrast, the ISP projected development plans continue to increase to replace retiring generation and meet projected demand growth. By 2028, approximately 7 GW of additional wind and solar generation is projected to be built in the ISP sensitivities, compared to the core ESOO scenarios.

Across all ESOO scenarios and sensitivities, Victoria and Queensland are projected to have the highest level of wind and solar generation development. In the ESOO scenarios, this is based on current commitments. In the ISP sensitivities, this projected development is driven by the Victorian Renewable Energy Target (VRET) and Queensland Renewable Energy Target (QRET).

Because ESOO modelling has been completed more recently, additional generation projects are now committed and will be operating earlier than was assumed in ISP modelling. This highlights how rapidly renewable generation is currently being developed, and serves to further emphasise the need for immediate action to develop the transmission augmentations identified in the ISP to deliver cost savings to consumers.

Figure 20 Intermittent generation development – ESOO (committed) and ISP projections

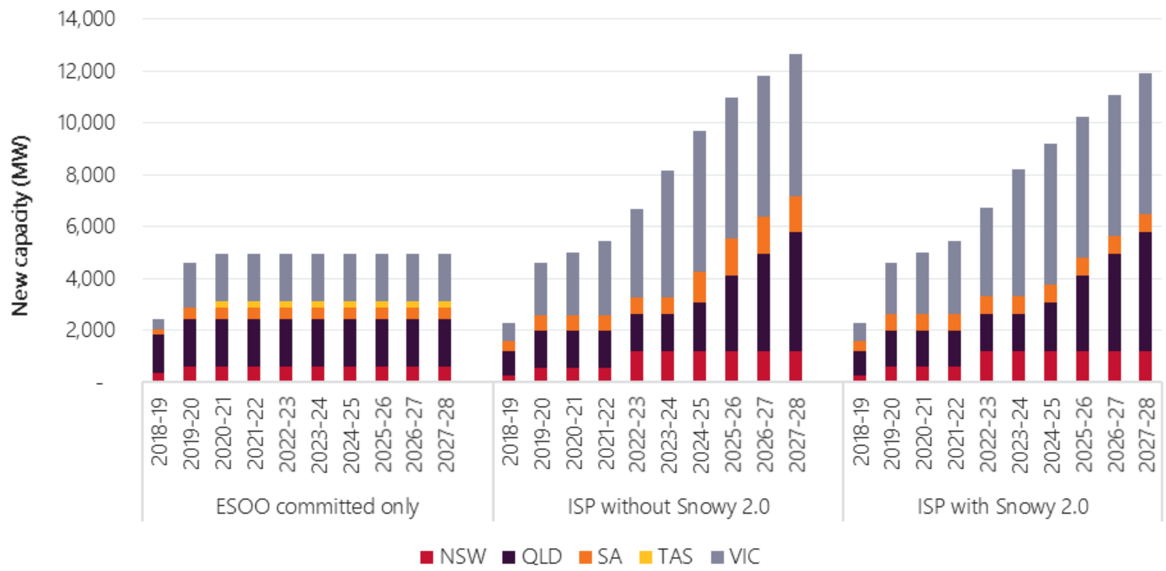
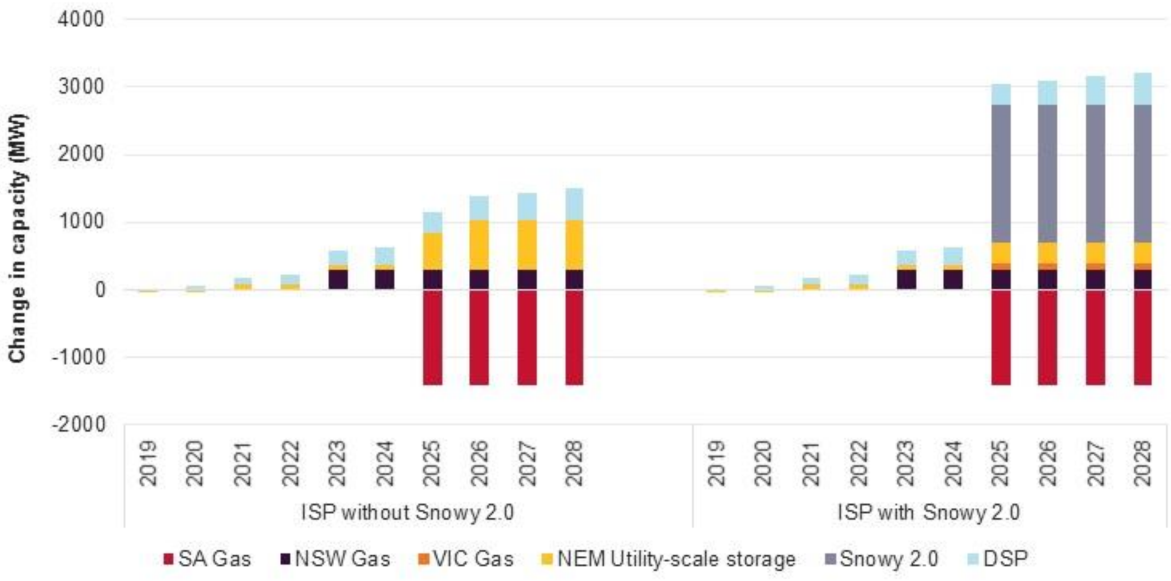


Figure 21 further illustrates the differences between the ESOO and ISP developments, focusing on the difference in non-intermittent capacity in the ISP sensitivities compared to the ESOO scenarios. It also shows projected mothballing of GPG in South Australia that was assumed in the ISP to coincide with the development of the RiverLink interconnector between New South Wales and South Australia in the mid-2020s.

The ISP highlighted that interstate energy interchange to take advantage of location diversity, coupled with large-scale storage and flexible gas-powered generation, are essential components of a system that relies on significant levels of variable, zero-fuel cost (and hence low marginal cost) renewable energy. Without these components, reliability could be compromised, with full dispatchability not being achievable in all hours.

Figure 21 Additional dispatchable generation in ISP sensitivities



4.3 Generation availability

4.3.1 Dispatchable generation

AEMO models the capabilities of dispatchable generation capacity by applying inputs sourced from market participants. The maximum capacity of each generating unit is provided by market participants through the Generation Information survey process. Through this process, each participant provides expected summer and winter available capacity over the 10-year modelling horizon. These capacities represent the expected capability of the units during temperatures consistent with a 1-in-10 demand peak in each region, and reflect the capability of the generator assuming everything is in service.

Market participants also provide AEMO, via an annual survey process, with details of the timing and size of historical unplanned generator outages. This data is used to calculate the probability of full and partial forced outages, which are then applied randomly to each unit in the ESOO modelling. To protect the confidentiality of this data, AEMO calculates outage parameters for a number of technology aggregations.

Analysis of this aggregated historical outage data has highlighted an emerging trend of deteriorating plant reliability, which is reflected in this ESOO modelling.

Table 10 shows the outage assumptions used in the 2018 ESOO, including a comparison of the full forced outage rate against the 2017 ESOO assumptions. Further details on the calculation and assessment of generator outage parameters are provided in Appendix A1.

Table 10 Forced outage assumptions (2018 ESOO)

Generator aggregation	Full outage rate – 2018 ESOO	Full outage rate – 2017 ESOO	Partial outage rate	Partial derating	MTTR^A – Full outage (hours)	MTTR – Partial outage (hours)
Brown coal	5.34%	4.10%	13.32%	19.18%	40	7
Black coal QLD	2.42%	2.05%	13.51%	16.94%	53	16
Black coal NSW – until 2022	6.56%	2.05%	25.81%	19.98%	135	19
Black coal NSW – after 2022	3.88%	2.05%	23.45%	17.76%	102	16
CCGT	1.33%	0.62%	0.36%	42.76%	17	36
OCGT	3.56%	0.66%	0.28%	26.91%	15	21
Steam Turbine	4.58%	1.73%	11.25%	22.85%	124	75
Hydro	1.58%	0.82%	0.01%	17.26%	15	7

A. MTTR = Mean time to repair: this parameter sets the average duration (in hours) of generator outages.

4.3.2 Intermittent generation

The 2018 ESOO modelled intermittent generation by considering eight historical reference years, which reflect the weather conditions that drove demand and wind and solar production between 2010-11 and 2017-18[64]. This approach preserves any correlation between intermittent generation and demand, and between intermittent generators in different locations.

Where possible, AEMO used actual generation performance from a generation site, or nearby. Where this data was unavailable or unsuitable, AEMO used historical meteorological data for the site, and an energy conversion model based on the generator technology, to develop a generation forecast. The 2018 ESOO incorporated wind production data developed by DNV-GL for the assessment of REZs in the 2018 ISP.

4.4 Transmission modelling

4.4.1 Existing transmission limitations

No interconnector augmentations are currently committed, so none were modelled in the core ESOO scenarios. The modelling in the core ESOO scenarios therefore used existing transmission limits and interconnector capacities, assuming interconnector limits currently in effect continue to apply.

In particular, ESOO modelling assumed:

- The Heywood interconnector continues to operate with a limit of 600 MW for transfers from Victoria to South Australia, and a limit of 500 MW for transfers from South Australia to Victoria, based on current constraint equations.
- The Basslink interconnector operates with a 478 MW limit in both directions based on forward-looking transfer capabilities supplied in the Medium-term Projected Assessment of System Adequacy (MT PASA)[65]. This represents a reduction in transfer capacity from Tasmania to Victoria of 116 MW compared to the 2017 ESOO.

[64] The 2017 ESOO modelled seven reference years: 2009-10, and 2011-12 to 2016-17.

[65] Information used in the 2018 ESOO was valid as at 1 July 2018. AEMO notes that Basslink has more recently increased its transfer capacity in MT PASA, however the timing of any such increase is still uncertain and subject to change. AEMO will continue to monitor progress on any change in rating as part of summer readiness, and will provide an update if any change materially alters this reliability assessment.

The ESOO model applied a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM. These constraint equations act at times to limit generation, but also frequently limit interconnector transfer capacity.

4.4.2 Transmission outages

For the first time, the 2018 ESOO includes the impact of a number of key unplanned transmission line outages or deratings which affect inter-regional transfer capability (see Table 11). AEMO assessed the probability of these outages using historical outage data since 2007.

Three key flow paths were chosen on which to assess the impact of transmission outages:

- Dederang to South Morang – the double circuit line from Dederang to South Morang is the critical flow path between northern Victoria and Melbourne. An outage of this line limits the ability to import generation from New South Wales and results in higher levels of curtailment for hydro generation in the north of Victoria. These lines are susceptible to the impact of bushfires.
- Heywood to South East – the double circuit line between Heywood and South East is also known as the Heywood interconnector. An outage at one of the two lines was used to represent the incidence of an outage on the flow path between Melbourne and Adelaide.
- Basslink – the interconnector between Tasmania and Victoria has had a number of forced outages in recent years. The extended outage in 2015-16 was excluded from the calculation of the Basslink outage rate.

Table 11 Transmission outage rates

	Unplanned outage rate (%)
Dederang – South Morang	0.32
Heywood – South East (Heywood interconnector)	0.15
Basslink	0.10

4.4.3 Interconnector augmentations in the ISP

Both ISP sensitivities incorporated the same transmission development plan, which includes augmentations of existing interconnectors and the establishment of the RiverLink interconnector. The ISP interconnector assumptions are summarised in Table 12.

Table 12 Interconnector development in ISP

	Start date	Exporting region	Importing region	Export capacity	Import capacity
Minor VIC to NSW upgrade	2019	VIC	NSW	170	0
Minor NSW to QLD upgrade	2019	NSW	QLD	460	190
Medium NSW to QLD upgrade (additional)	2022	NSW	QLD	0	378
RiverLink	2024	NSW	SA	750	750
VIC-SA[A]	2024	VIC	SA	100	100

A. Additionally, the increase in the VIC-SA transfer limit associated with the RiverLink upgrade is assumed to include the minor transmission works which are required to complete the Heywood augmentation.

5. NEM-wide outlook

This chapter provides a supply adequacy overview for the NEM as a whole, under the Neutral demand scenario. It includes:

- An overview of trends and projections.
- The supply-demand outlook, highlighting projected USE and any potential reliability gaps.
- Short-term risks and actions.
- The effect of ISP development plans on reliability outcomes.

Key insights

- The 2018 ESOO highlights that, without RERT, the risks of supply shortfalls in Victoria this summer would remain high, with projected USE only marginally below the reliability standard.
- AEMO has commenced work to prepare the power system for the summer ahead. This includes procuring RERT, and closely collaborating with industry and government to maximise available generation and resilience of energy infrastructure.
- Without this action before summer 2018-19, should a 10% POE peak demand occur, the forecast risk of load shedding in Victoria would be over 80%, with a 60% chance of exceeding the reliability standard.
- The key drivers of the heightened USE risk assessment in the short term are:
  - An increase in the projected likelihood of unplanned (or forced) generation outages, based on historical outage data provided by market participants.
  - An increase in expected peak demand across Victoria and South Australia under 10% POE demand conditions.
  - A reduction in the export capacity of Basslink.
- Some scarcity risks are forecast in South Australia and New South Wales, despite the expected level of USE remaining below the reliability standard in the short term. The ESOO projects and 8% to 10% chance of some level of supply interruption in either region this summer, due to the correlation of effects of extreme weather on both supply and demand.
- Periods of forecast USE remain concentrated during the summer months, and generally between 4.00 pm and 9.00 pm, depending on the region.
- Reliability gaps are projected in Victoria/South Australia and New South Wales after the retirement of Torrens Island A and Liddell power stations in the early 2020s, in the absence of further investment beyond what has already been committed for construction.
  - Once a reliability gap is observed in the forecast, the size of the gap is projected to increase year on year due to growth in maximum demand forecasts.
  - To maintain reliability within the reliability standard after the closure of Liddell Power Station, the equivalent of 350 MW of dispatchable capacity or equivalent (beyond that already operating or

committed) would be required by 2023-24 across Victoria, New South Wales, and South Australia, rising to 1,160 MW by 2027-28.

  – Transmission augmentations and new lines, as recommended in the ISP, would reduce the need for more dispatchable capacity by alleviating transmission congestion, leveraging resource diversity, and maximising the value of the existing generation fleet.

- This highlights the need for a portfolio of resources including renewable generation, flexible thermal generation, storage, transmission augmentations, and demand response to close the reliability gap at lowest cost to consumers. The ISP portfolio development plans would be sufficient to maintain reliability.
- There are no supply scarcity risks forecast in either Tasmania or Queensland over the 10-year modelling horizon.

The 2018 ESOO provides information on the adequacy of existing and committed capacity to meet projected peak demand and consumption across the NEM. This section highlights the heightened risk of supply shortfalls in the short term, and identifies when reliability gaps are expected to occur in the medium to longer term, in the absence of any further market response.

USE outcomes are also provided under the two alternative ISP plans to illustrate the projected impact on reliability outcomes of a portfolio of resources – including utility-scale renewable generation, storage, DER, flexible thermal capacity, and transmission – as generators withdraw from the market.

As no forecast USE is observed in Queensland or Tasmania, these regions have been removed from the presentation of USE outcomes in this chapter.

The reliability assessments assume that all registered market participants' capacity, if not announced as withdrawn, would be made available if sufficient notice was given of likely shortfalls. The assessments do not, however, include any additional capacity that could be made available through RERT. Specifically, the assessments:

- Include all scheduled and semi-scheduled capacity not currently PASA available (that is, not currently available within 24 hours recall) but reported by market participants as available under ESOO reporting requirements.
- Do not include Tamar Valley CCGT in Tasmania, which Hydro Tasmania has advised is currently mothballed, but could be returned to service with three months' notice or less.
- Do not include the South Australian temporary diesel generators that were installed last summer to be used as a last resort to avoid load shedding. These generators are operating out of market on instructions from the South Australian Government.

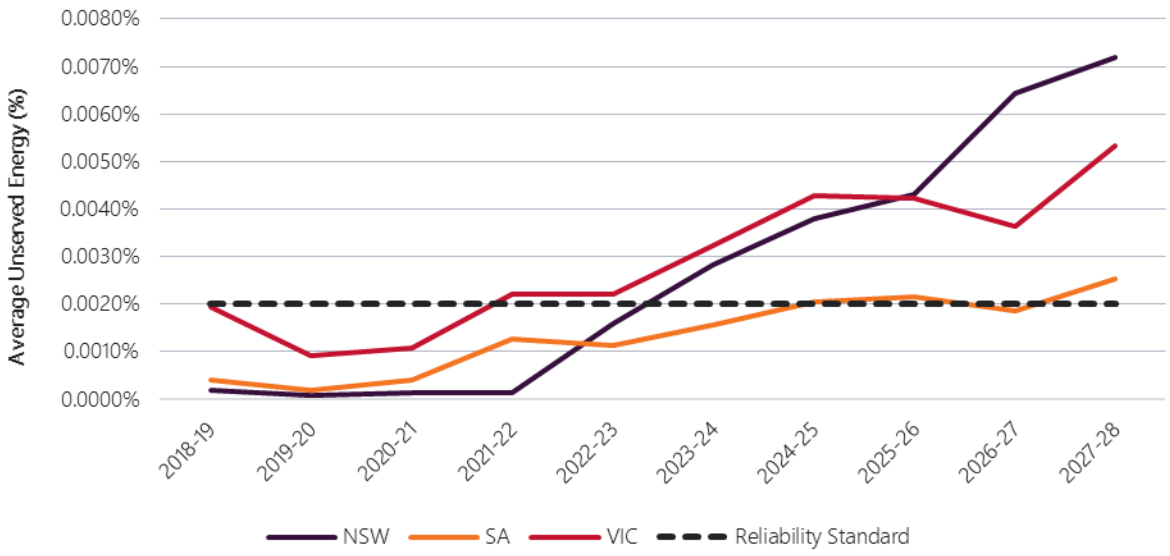
5.1 Overview of reliability assessment

The 2018 ESOO confirms that, without the procurement of additional reserves, there would be a high risk of USE in Victoria in the coming summer, with average forecast USE only marginally below the reliability standard.

The USE forecast provided in Figure 22 illustrates this risk, and also shows that:

- After this summer, the risk of USE is forecast to reduce in the short term, due to a slight reduction in forecast peak demand and the introduction of additional renewable generation.
- As the forecast peak demand begins to grow, and power stations retire at Torrens Island A (2019-21) and Liddell (2022), USE is projected to begin rising. Forecast USE is above the reliability standard in Victoria by 2021-22, in New South Wales by 2023-24, and in South Australia by 2024-25.

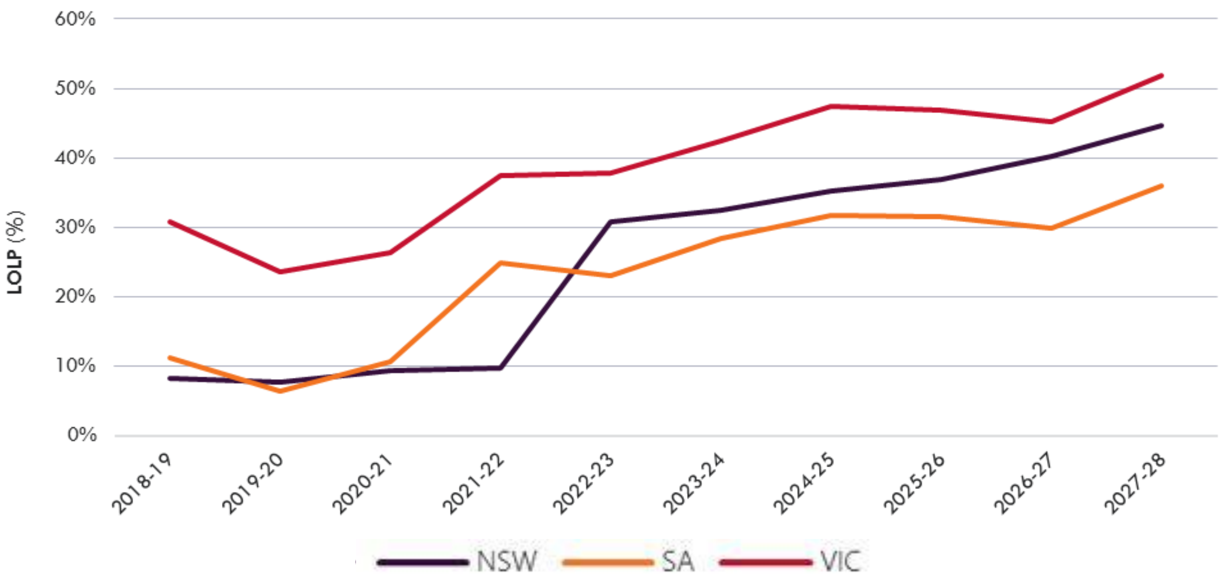
Figure 22 Forecast USE outcomes, Neutral demand, committed projects only



Supply reliability may also be measured using metrics such as Loss of Load Probability (LOLP). LOLP is the probability that in any year, there are periods where there is a supply shortfall. It highlights the likelihood of some USE occurring, but does not indicate the severity of any loss of load event.

Figure 23 shows forecast LOLP for the Neutral demand scenario, based on weighted 10% POE and 50% POE peak demand conditions. It shows that, although Victoria is forecast to meet the reliability standard in 2018-19, there is a high projected likelihood (about 30% chance) of some instances of load shedding.

Figure 23 Forecast LOLP, Neutral demand, committed projects only

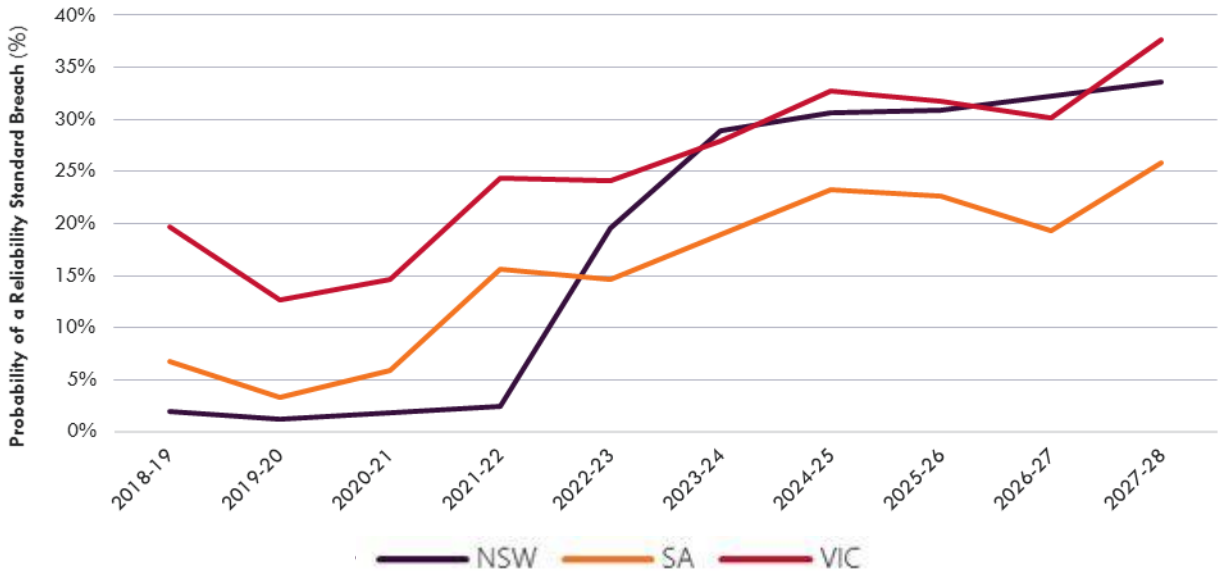


The extent of the forecast reduction in the LOLP in Victoria over the following two years is much more moderate than the forecast level of USE as measured by the reliability standard (shown in Figure 22). This indicates that, while additional variable renewable energy in Victoria is projected to help reduce the annual volume and severity of USE, the forecast probability of some USE occurring is still quite high. In general, the

USE percentage in the reliability standard is a much more sensitive measure than other reliability metrics such as LOLP.

Figure 24 shows the probability that USE will exceed the reliability standard. Each region follows a similar trajectory to LOLP, although the magnitude of changes from year to year is amplified, because this metric includes some element of USE severity.

Figure 24 Forecast probability of exceeding reliability standard, Neutral demand, committed projects only



AEMO will continue to explore the value of reporting alternate reliability metrics such as LOLP in the coming year to help inform decision-making. It is important that the reliability metrics, and mechanisms to operationalise these metrics, provide the right signals for investment in supply and demand resources that can help ensure dispatchability in all hours.

5.2 Short-term risks and actions

The 2018 ESOO confirms the need for a series of actions to increase resource availability this summer, requiring collaboration across industry and governments, as planned in AEMO's summer readiness program. Without this action, there remains a heightened risk of USE this summer, particularly in Victoria. The level of risk is similar to that forecast in the 2017 ESOO for the for 2017-18 summer.

Without additional reserves, the projected risk of a shortfall in Victoria in 2018-19 is 31%, with USE outcomes typically occurring in January and February between 4.00 pm and 7.00 pm. The majority of forecast USE events shed less than 500 MW and last for less than four hours. There is a 20% likelihood that Victoria will exceed the reliability standard this summer. Due to the level of variability in supply from thermal generation as a result of coincident unplanned outages and the variability of intermittent generation at times of high demand, there is a significant tail risk where USE could be well above the standard, as shown in Figure 25.

The level of projected risk in other regions in 2018-19 is considerably lower:

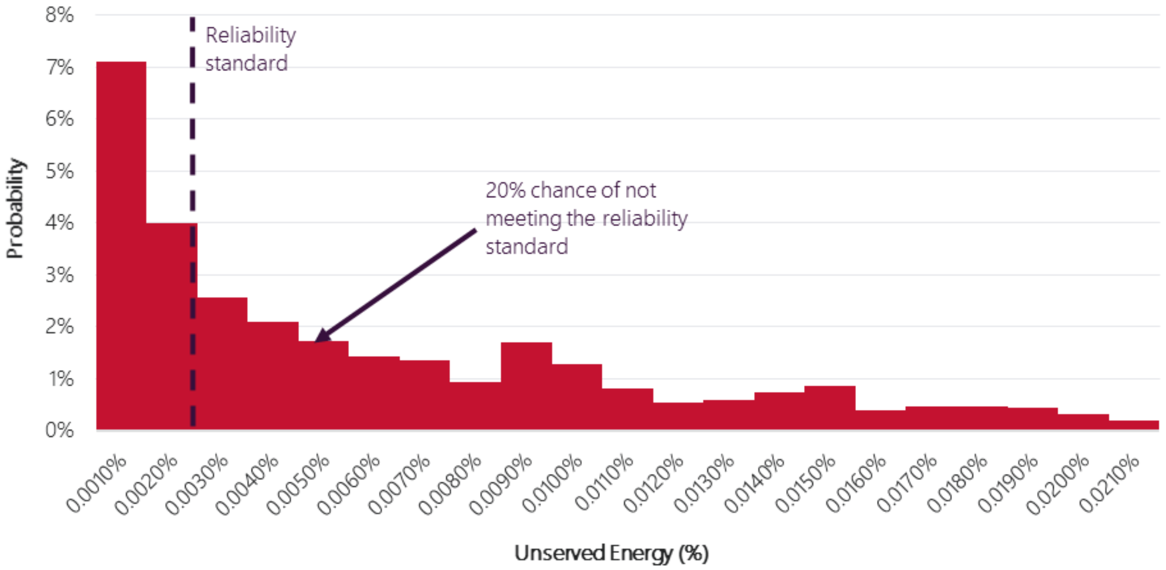
- In South Australia there is an 11% chance of load shedding, with a 7% chance of exceeding the reliability standard.
- In New South Wales there is an 8% chance of load shedding, with a 2% chance of exceeding the reliability standard.

- No USE occurs in either Tasmania or Queensland in the market simulations.

The 'long tail' in the USE distribution shown in Figure 25 highlights a range of possible outcomes which AEMO, as system operator, would need to manage to protect consumers against supply interruptions. With both demand and supply now exposed to the vagaries of weather, the impact of extreme weather events is highly correlated, resulting in reductions in supply at the same time as demand increases, and this is contributing to the long tail of the USE distribution.

Further, uncertainty in NEM forecasts is inevitable, so all estimates of reserve requirements must be regarded as subject to progressive refinement. Minor changes to the outlook for demand or supply next year could lead to supply shortfalls and result in the reliability standard being exceeded.

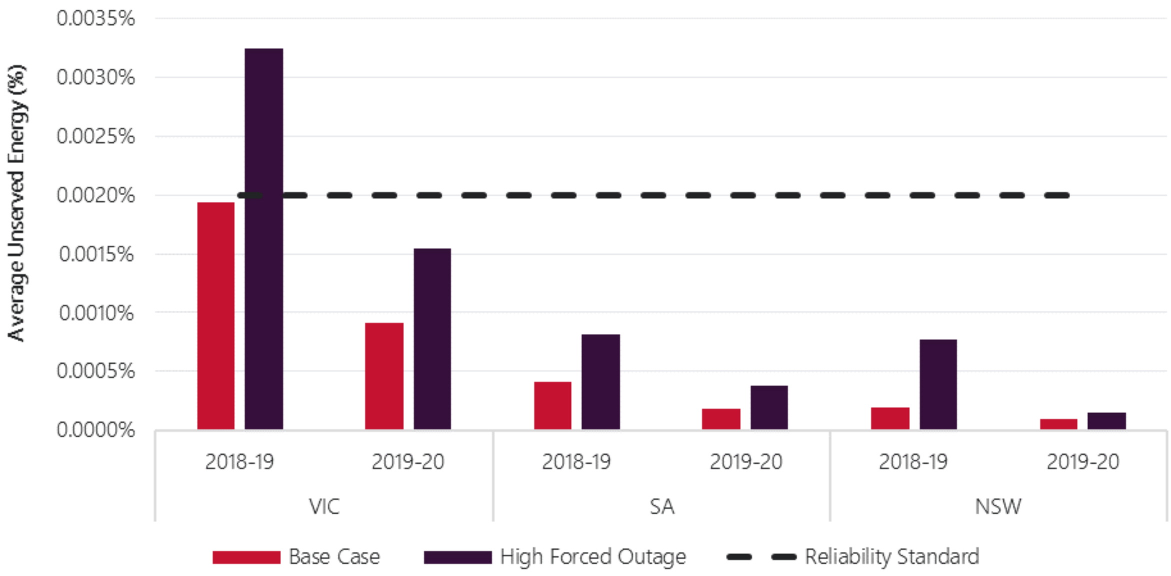
Figure 25 Range of USE outcomes, Victoria 2018-19 (weighted outcomes)



The level of forecast USE in 2018-19 in Victoria is higher than was previously forecast, and more in line with the scarcity risks observed in the region in summer 2017-18. This is primarily due to an increase in the forced outage rate assumptions, based on updated historical outage data provided by participants. The level of reliability varies considerably, even when aggregated by technology and over financial years. Extended outages in particular can have a significant impact on reliability metrics.

As generator reliability is so variable, AEMO modelled a sensitivity which uses the highest aggregate outage rates observed for each technology type across the last three years of historical outage data. When these outage rates are applied, the level of USE increases by approximately 50%, as shown in Figure 26.

Figure 26 Sensitivity outcomes – impact of lower generator reliability



These outcomes show the sensitivity of reliability outcomes to the reliability of the generation fleet in a system with a tight supply-demand balance. As the existing thermal fleet ages and approaches end of technical life, there is a risk that reliability will continue to deteriorate, as there will likely be less incentive for generators to incur significant maintenance expenditure.

Reliability outcomes are also highly sensitive to extreme weather events which drive peak demand periods. Figure 27 compares USE outcomes on a weighted basis against outcomes which consider only a 10% POE summer peak, and shows:

- Under these more extreme weather conditions, the level of USE is more than 0.006% in Victoria in 2018-19, over three times the reliability standard. The extent of expected load shedding would be of a scale equivalent to 187,000 households being without power for over seven hours.
- The LOLP increases to over 80%, and the likelihood of USE in excess of the reliability standard increases to over 60%, as shown in Figure 28.
- In South Australia and New South Wales, the level of USE is approximately 200% higher than under a weighted expectation of peak demand conditions.

If the coming summer experienced peak demand conditions similar to 10% POE forecasts, approximately 380 MW of additional supply or demand response would be needed in Victoria and South Australia combined to close the gap between expected USE and the reliability standard. Given current weather conditions, bushfires may also threaten the power system this summer, limiting inter-regional transfer capabilities and further increasing supply scarcity risks.

Figure 27 Forecast USE outcomes, weighted vs 10% POE

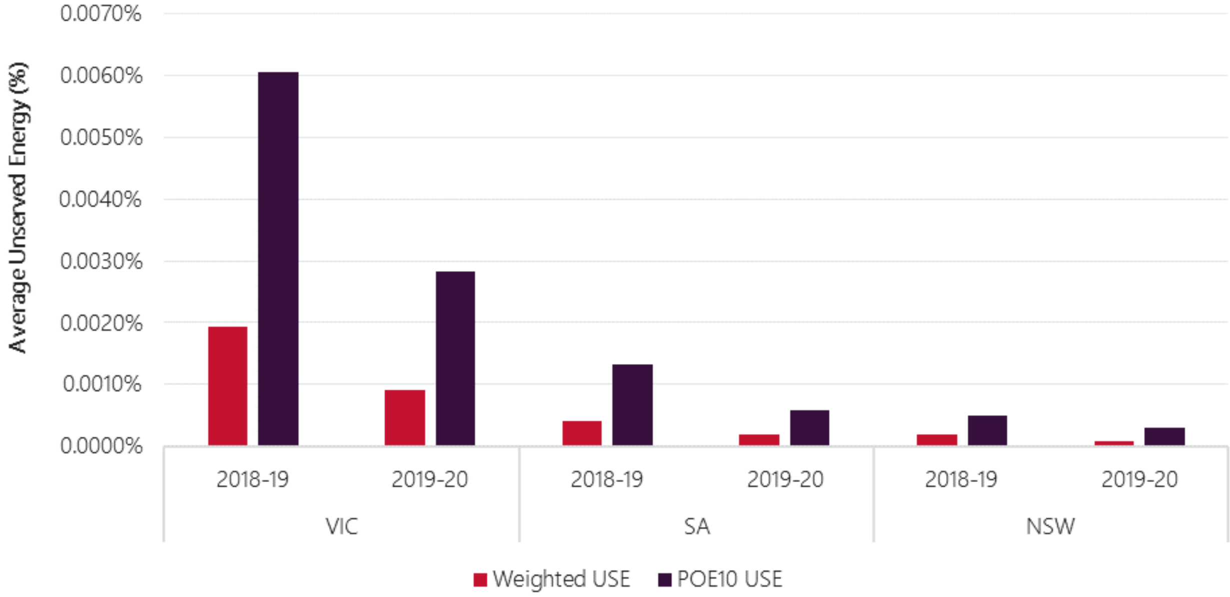
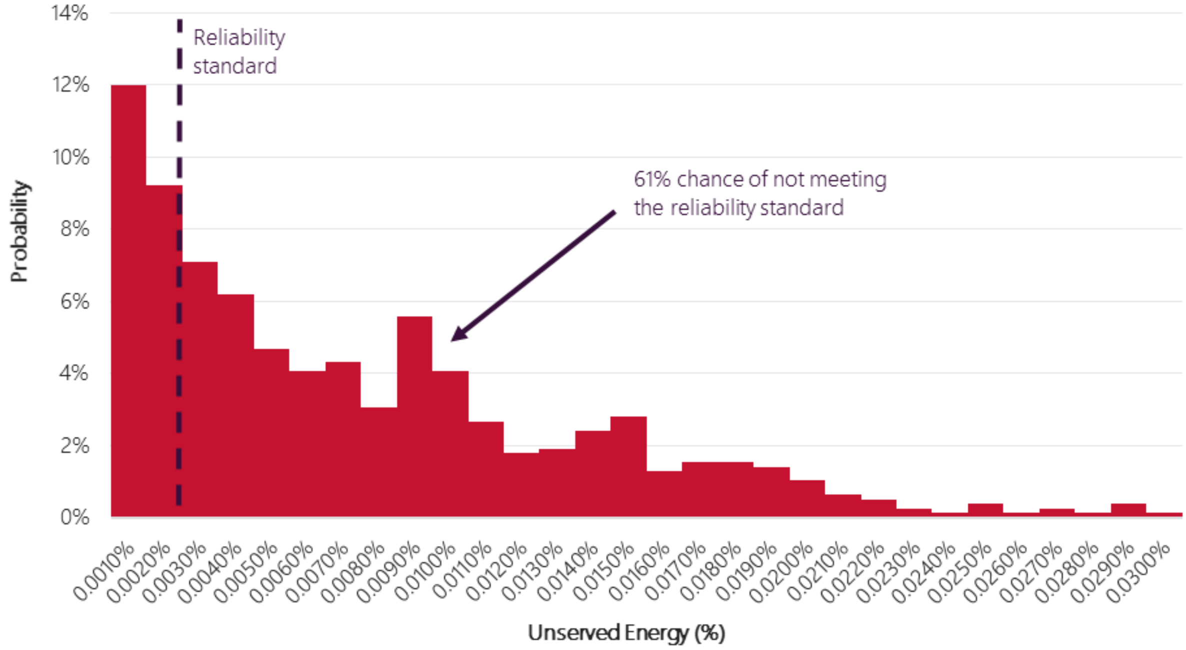


Figure 28 Range of USE outcomes, Victoria 2018-19 (10% POE outcomes)



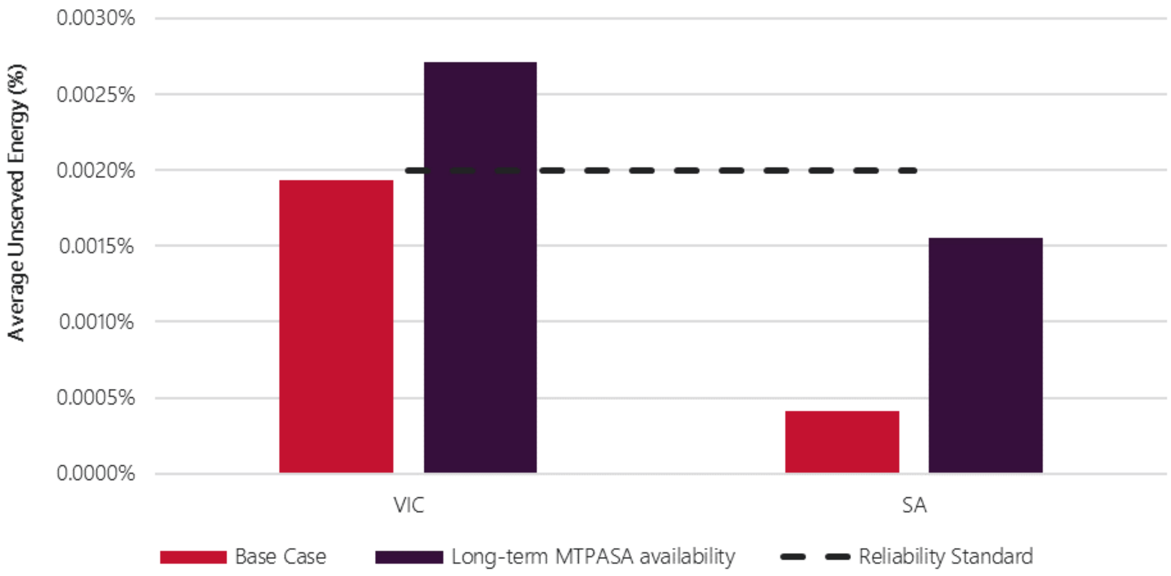
AEMO also forecasts USE over a two-year period using the MT PASA system. In May 2018, AEMO deployed the new probabilistic MT PASA system, which uses modelling techniques equivalent to the ESOO, but for which participants provide capacity and energy limitation information on a daily and weekly basis respectively. MT PASA also differs from the ESOO in that it incorporates planned transmission outages.

Based on current participant offers, the aggregate PASA availability of scheduled (that is, not intermittent) generators is approximately 250 MW below the aggregate summer capacity modelled in the 2018 ESOO in South Australia. The ESOO assumes that any generation that is not available in MT PASA would become available if sufficient notice was given of a likely shortfall, or if directed to become available.

AEMO modelled a sensitivity which withdraws capacity from South Australia equivalent to this difference, to assess supply scarcity risks if this generation was unable to be made available in time. The outcomes shown in Figure 29 illustrate that this reduction in capacity has a significant impact not only on South Australia, but also on Victoria, which would then exceed the reliability standard. Under this sensitivity, Victoria and South Australia have a combined weighted reliability gap of 120 MW, and a reliability gap of 525 MW under 10% POE conditions (for definition of reliability gap, refer to Section 1).

As part of summer readiness, AEMO is continuing to work with participants to ensure all generation is available when needed to meet peak demands. Fuel availability for generation will also be reassessed. In particular, the potential impact of the New South Wales drought on water available for hydro generation and as cooling water for thermal generation will be closely monitored and reported in an updated Energy Adequacy Assessment Projection (EAAP) later in the year.

Figure 29 Sensitivity outcomes – impact of lower availability based on typical summer offers



The ESOO modelling assumes all generation and transmission maintenance can be undertaken during periods which do not create risks of reliability shortfalls. However, given the tight supply-demand balance in the current system, in reality this is becoming more challenging. At times there is limited flexibility as to when outages can occur, and the time to recall a generating unit or transmission outage can be long.

Furthermore, there are emerging challenges in South Australia where generation and transmission maintenance needs to be rescheduled to maintain system strength during periods of low demand. This is typically during shoulder months, when traditionally maintenance would be scheduled in preparation for higher demands in winter and summer. Given the limited window in which maintenance can be scheduled, there are increasing operational risks associated with maintaining reliability and system security when maintenance does proceed. On the other hand, if preventative maintenance cannot occur in a timely manner due to power system security concerns, there is higher risk of a reduction in plant reliability during high demand periods.

The current tight supply-demand conditions, and sensitivity to generator performance, availability, and demand, demonstrate both the need for clear reliability obligations and the importance of short-term mechanisms, such as long-notice RERT, which provide AEMO with the ability to contract additional supply and demand resources, if required, to ensure the reliability standard is not exceeded.

5.3 Emerging reliability gap

For the purpose of this 2018 ESOO analysis, and to inform decision-making, the reliability gap has been calculated in two ways:

1. Based on the firming capability needed to meet the reliability standard based on weighted expectation of outcomes under 10% POE and 50% POE conditions.
2. Based on the firming capability needed to meet the reliability standard under 10% POE conditions, recognising that the reliability standard sets a maximum expected unserved level not to be exceeded for a given financial year.

Calculating the reliability gap under 10% POE demand conditions improves understanding of the risks and power system vulnerabilities under more extreme but plausible weather conditions.

The level of dispatchable capacity required to close the reliability gap is shown in Table 13. Note that the gap in Victoria and South Australia has been combined, because these regions frequently share a reserve shortfall, and many possible combinations of resources across these two regions could reduce USE to below the standard in both regions.

While supply-demand balance is tight this summer, over the following two years the level of forecast USE in Victoria reduces by approximately 50% (although small changes in either supply or demand forecasts could materially change this reliability outlook). This reduction in USE is attributable to the continued growth in renewable generation, particularly in Victoria. Even though USE is forecast to remain below the reliability standard on an expected basis, under 10% POE conditions, the risk of load shedding remains high, and USE would be expected to exceed the standard.

No reliability gap is projected over this three-year period in New South Wales and South Australia, even under 10% POE demand conditions.

After the retirements of Torrens Island A in 2021-22 and Liddell in 2022-23, reliability gaps emerge in all three regions, and these gaps are projected to increase year on year to the end of the 10-year outlook as maximum demand grows.

Table 13 Reliability gap – capacity required to meet reliability standard under different demand conditions

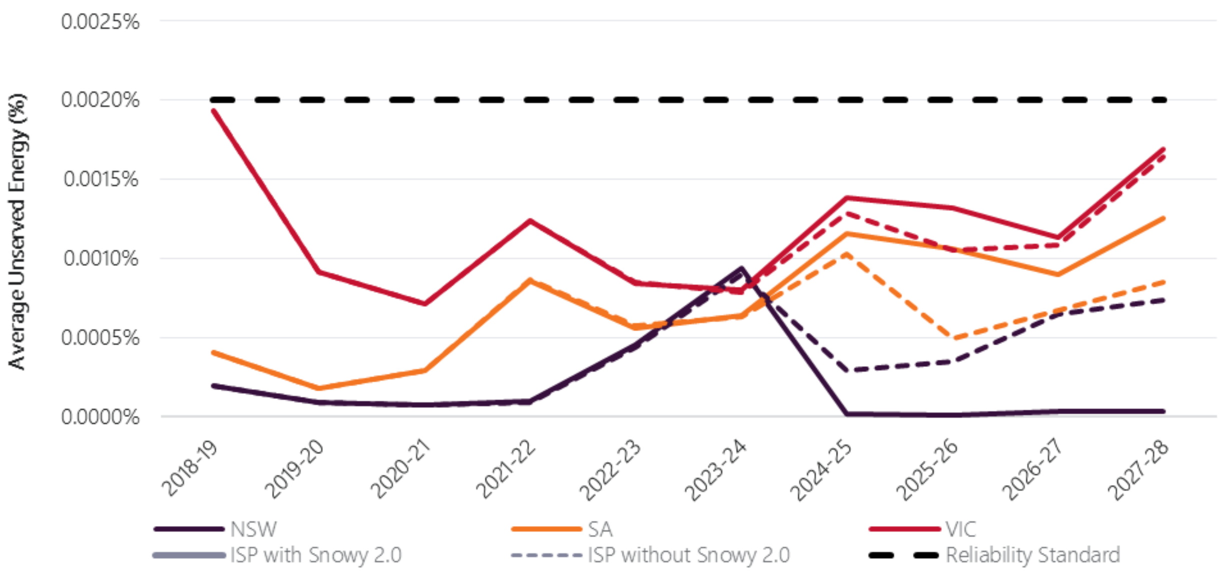
	Weighted USE ≤ 0.002% (MW)		10% POE USE ≤ 0.002% (MW)	
	South Australia/Victoria	New South Wales	South Australia/Victoria	New South Wales
2018-19	0	0	380	0
2019-20	0	0	130	0
2020-21	0	0	190	0
2021-22	40	0	483	0
2022-23	40	0	460	380
2023-24	200	150	650	640
2024-25	340	310	790	810
2025-26	330	380	835	885
2026-27	260	620	755	1,130
2027-28	460	700	985	1,220

AEMO will work with the affected regions to support activities necessary to close the gap in the near term. In the longer term, AEMO will contribute to processes designed to establish changes in approaches to ensure sufficient resources are developed to meet emerging reliability requirements.

5.4 Impact of the ISP development plans

Figure 30 shows forecast USE outcomes for the two ISP ESOO sensitivities, which assume that the identified reliability gaps are filled at lowest cost by a portfolio of resources including transmission development. Under both portfolio development plans, the forecast level of USE is within the reliability standard. These results show that the reliability gap could be closed by a portfolio of resources including utility-scale renewable generation, storage, DER, flexible thermal capacity, and transmission.

Figure 30 Forecast USE outcomes, 2018-19 to 2027-28, Neutral demand, ISP development plans



The ISP sensitivities relied on new, geographically and technologically diverse, variable renewable generation, supported by the augmentation of inter- and intra-regional transmission capacity, to fill the reliability gap. The transmission development more effectively utilises the diversity in demand and intermittent generation, particularly given the substantial level of renewable capacity installed in this scenario. The interconnector augmentations also allow greater access to Queensland, which is forecast to continue to have a surplus of generation capacity.

These studies further demonstrate the limitations in the current transmission network which limit the ability for regions to share existing reserves at times of tight supply-demand balance, particularly between Victoria/South Australia and New South Wales. Given the relatively low levels of correlation in demand and intermittent supply between these regions, an increase in the transfer capability of key flow paths would reduce the need for other sources of local supply.

5.4.1 Potential role of distributed energy resources

The increase in DER uptake has the potential to play a key role in addressing emerging reliability gaps. The modelling of DER in the 2018 ESOO reflects current uncertainty over whether operational signals and market design are appropriate for extracting the maximum benefit from DER, particularly battery storage, in providing a source of supply to the grid at times of peak demand.

Figure 31 shows forecasts for total contribution from DER across Victoria, South Australia, and New South Wales, compared to total installed capacity. This shows that, if better coordinated, there is the potential for DER to provide up to 500 MW of additional supply at times of peak demand by 2028[66].

It is necessary to develop monitoring and dispatch systems and regulatory frameworks that enable DER to operate to meet power system needs, including how battery storage is incentivised and coordinated at times of peak demand.

Figure 31 Forecast maximum potential of DER in Victoria, South Australia, and New South Wales, 2018-19 to 2027-28

AEMO has commenced a broad program of work aimed at integrating DER into the system and market[67], and is working closely with the Energy Networks Association (ENA), Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), Australian Renewable Energy Agency (ARENA), and industry players to deliver on focus areas including:

- DER visibility – following a rule change proposal, AEMO will establish a register of DER resources to inform operational and market processes. As part of the initiatives below, AEMO is also exploring more granular visibility of DER, particularly as these resources are integrated into the grid and market dispatch processes.
- Connection framework and technical standards – AEMO is working with the ENA to inform the development of a national framework for the connection of distributed resources. This is aimed at the timely and effective connection of these resources onto the grid and ensuring they met appropriate network and power system needs. AEMO is working with Standards Australia on the development of standards for distributed resources, and is also reviewing the need for additional DER technical standards.
- Market access – AEMO is working with the AEMC on changes to the regulatory regime to facilitate DER access to energy, ancillary and reserve markets. These regulatory framework reviews will be informed by a range of AEMO pilot programs.
- Open Energy Networks – AEMO and the ENA have commenced a body of work, in consultation with industry, to look at models that enable DER integration and optimisation, taking into account both transmission and network constraints, and aimed at informing regulatory framework changes. Following the

[66] This is an upper estimate, because there are some occasions where USE events would last for more than 2.5 hours, and therefore no level of coordination would allow batteries to maintain their level of discharge across the entire USE event without deeper storage capability.

[67] For more information, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program.

release of a consultation paper in June 2018, AEMO and the ENA held a series of workshops across Australia and received comprehensive feedback with over 60 submissions.

- Pilot programs – AEMO is establishing a three-phase trial program. The first two phases are focused on enabling virtual power plants and aggregated DER more generally to offer energy and frequency services into the market, with these resources being dispatched alongside other resources. The third phase aims to progress the trialling of a distributed market model and AEMO will work with distribution businesses to progress this.

6. Regional outlook

This chapter provides a supply adequacy overview for each NEM region, including:

- Overview of trends and projections.
- Summary of generation changes and investment trends.
- The supply-demand outlook, highlighting any reliability gaps and projected USE.
- The effect of ISP development plans on reliability outcomes.

6.1 New South Wales

The 2018 ESOO projects:

- The risks of load shedding remain relatively low in New South Wales over the next four years, with USE well within the reliability standard and less than 10% LOLP, although drought impacts on generation availability are being closely monitored.
- The forecast risk of USE increases after the retirement of Liddell Power Station in 2022-23, and continues to increase from that point onwards. Without further development, the reliability standard is forecast not to be met in the Neutral scenario by 2023-24, in the Fast change scenario by 2022-23 and in the Slow change scenario by 2026-27.
- A reliability gap of 150 MW is forecast from 2023-24, increasing to 700 MW by 2027-28, with most USE occurring in summer between 4.00 pm and 7.00 pm.
- The development of additional interconnection and dispatchable capacity in the ISP sensitivities reduces the level of USE to within the reliability standard.

6.1.1 Generation and storage changes

There are currently 618 MW of committed large-scale wind and solar projects in the region, summarised in Table 14.

Of this total, 413 MW of additional wind and solar projects have met AEMO's commitment criteria in the last quarter, highlighting the rapid rate of development.

Table 14 New committed generation and storage in New South Wales

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Coleambally Solar Farm	180	Oct 2018
	Beryl Solar Farm	98.4	Winter 2019
Large-scale wind	Crookwell 2 Wind Farm	91	Winter 2018
	Bodangora Wind Farm	113.19	Summer 2018-19
	Crudine Ridge Wind Farm	135	Summer 2019-20
Generator upgrades	Bayswater Power Station	100	2019-2022

6.1.2 Supply adequacy assessment

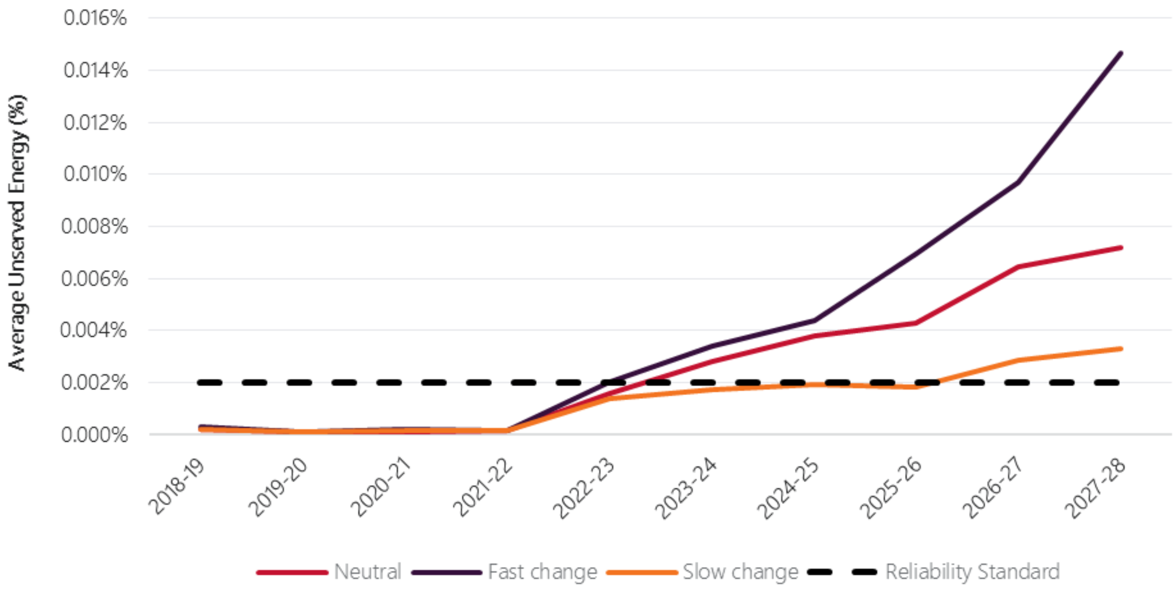
Figure 32 shows the projected level of expected USE for the Fast change, Slow change, and Neutral scenarios. These scenarios assume only currently committed generators enter the market over the ESOO timeframe.

The risk of USE over the next four years is low and New South Wales is forecast to remain well within the reliability standard. However, this assessment does not consider the potential impact of the New South Wales drought on water available for hydro generation and as cooling water for thermal generation this summer. This will be closely monitored and reported in an updated EAAP later in the year.

After the retirement of the Liddell Power Station in 2022, USE is forecast to rise sharply and continue to increase, across all scenarios. In the absence of new investment, the reliability standard is forecast over time to be exceeded in all ESOO scenarios, with the level of USE exceeding the 0.002% standard by:

- 2022-23 in the Fast change scenario.
- 2023-24 in the Neutral scenario.
- 2026-27 in the Slow change scenario.

Figure 32 Forecast USE outcomes, New South Wales, existing and committed projects only



The forecast size of USE events is shown in Figure 33, noting that over the first four years the number of USE events from which these distributions are based is very small. The 'box and whisker' plots show the magnitude of USE that has occurred in the market simulations. The figure shows for each year, the maximum, minimum, median, first, and third quartiles of USE across all simulations.

This figure shows that in 2022-23, for example, 75% of observed USE events are below 603 MW. By 2027-28, this increases to 899 MW. Over the large number of simulations run, the maximum observed USE tends to be very large, which is attributable to an unlikely combination of generation outages occurring at the time of peak demand.

Figure 33 also shows the reliability gap, defined by the additional resources required for expected USE to fall within the reliability standard. To help put this in perspective, 500 MW of USE in New South Wales is equivalent in scale to 250,000 households without power for an hour, although households are not necessarily the consumer segment that would first shed load.

Even with new firming capability meeting the gap, some USE outcomes are still expected under some conditions, typically when high demand coincides with low wind conditions and unfortunate combinations of generation outages.

In the early years in Figure 33, the reliability gap appears to be very low compared to the distribution of USE observed events. This is because there are relatively few USE events observed across simulations in those years. A small amount of additional dispatchable capacity would be sufficient to bring the expected annual USE level down below the reliability standard from an energy perspective, while being insufficient to cover all supply shortfalls from a capacity perspective. In later years, the reliability gap is relatively high compared to the size of the USE events, reflecting the high frequency of USE events that are expected to occur.

This also provides some indication of the level of utilisation required from new investment. When the reliability gap appears low relative to the distribution of USE observed events, any new supply or demand response would be needed infrequently to maintain reliability. As the reliability gap rises towards the top end of the distribution of USE observed events, the new dispatchable capacity would need to be utilised more often to maintain reliability below the standard.

Figure 33 Forecast size of USE events, New South Wales, Neutral, committed projects only (10% POE events)

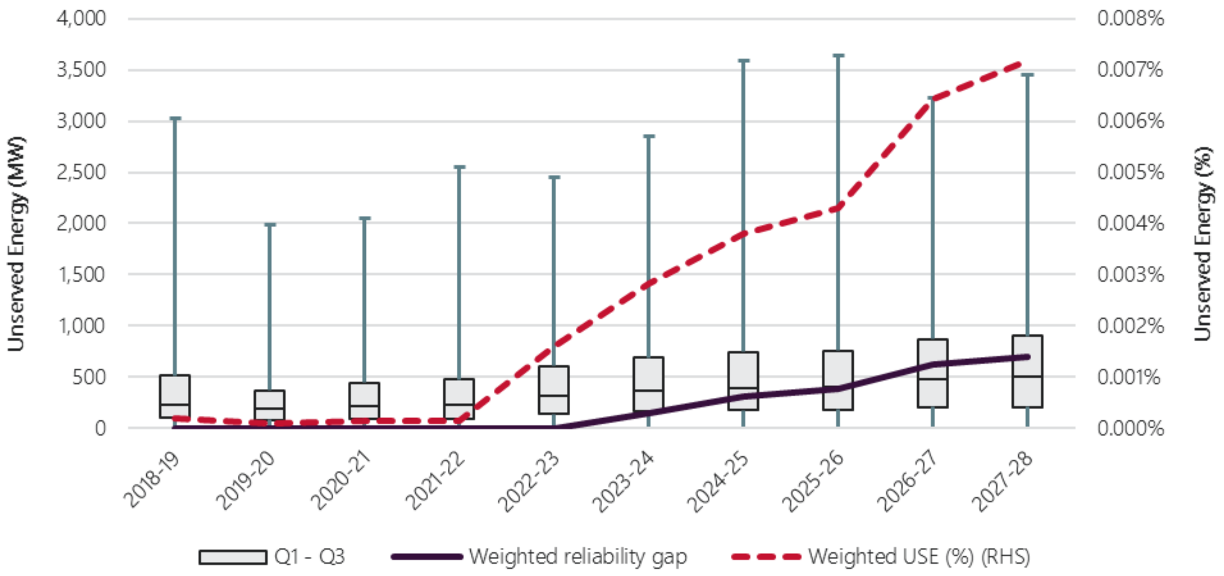
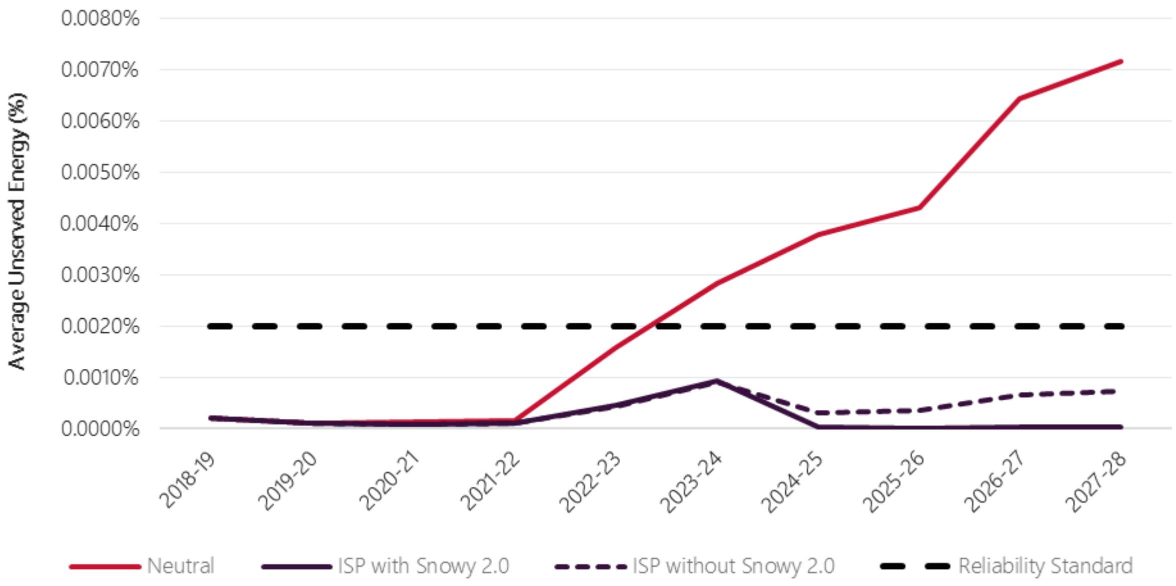


Figure 34 shows the level of USE observed in the Neutral ESOO scenario compared to the ISP development plans. Under both ISP plans, USE remains within the reliability standard. The reduction in USE relative to the

ESOO Neutral scenario is due to the effect of increased interconnection with neighbouring regions and additional dispatchable capacity installed in New South Wales (300 MW of open-cycle gas turbine [OCGT], and 2,040 MW of pumped hydro with Snowy 2.0).

Figure 34 Forecast USE outcomes, New South Wales, ESOO vs ISP development plans



The changes in capacity and interconnection between the ESOO and the ISP sensitivities that drive the reduction in projected USE are shown in Table 15.

Table 15 ISP developments in New South Wales (over and above committed) by 2028

Source	Capacity (MW)	ISP plan
Gas-powered generation (GPG)	301	Both development plans
Additional wind and solar generation in New South Wales	597	Without Snowy 2.0
	608	With Snowy 2.0
Utility-scale storage	2,040	With Snowy 2.0
Additional interconnection with Queensland	568	Both development plans
Additional interconnection with Victoria	170	Both development plans
Additional interconnection with South Australia	750	Both development plans

6.2 Queensland

The 2018 ESOO projects:

- A negligible level of USE across all scenarios in Queensland, which has a surplus of capacity and a relatively large pipeline of committed and proposed renewable generation development.
- The augmentations of the QNI interconnector between Queensland and New South Wales modelled in the ISP sensitivities utilise this surplus to reduce the risk of load shedding in New South Wales.

6.2.1 Generation and storage changes

There are 1,996 MW of committed large-scale wind and solar generation projects in Queensland, in addition to a battery storage project, listed in Table 16.

Table 16 New committed generation and storage in Queensland

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Daydream Solar Farm	167.5	Winter 2018
	Hamilton Solar Farm	57.5	Winter 2018
	Hayman Solar Farm	50	Winter 2018
	Whitsunday Solar Farm	57.5	Winter 2018
	Collinsville PV	42.5	Aug 2018
	Darling Downs Solar Farm	108.5	Aug 2018
	Oakey Solar Farm	25	Aug 2018
	Clermont Solar Farm	92.5	Oct 2018
	Kennedy Energy Park – Phase 1 – Solar	15	Oct 2018
	Lilyvale Solar Farm	100	Winter 2018
	Oakey 2 Solar Farm	55	Oct 2018
	Haughton Solar Farm	100	Summer 2018-19
	Ross River Solar Farm	128	Summer 2018-19
	Emerald Solar Park	72	Dec 2018
	Rugby Run Solar Farm	65	Dec 2018
	Childers Solar Farm	56	Feb 2019
	Susan River Solar Farm	75	Feb 2019
	Teebar Solar One	52.5	Jul 2019
	Yarranlea Solar Farm	102.5	Aug 2019
Large-scale wind	Kennedy Energy Park – Phase 1 – Wind	43.2	Oct 2018
	Mount Emerald Wind Farm	180.5	Oct 2018
	Coopers Gap Wind Farm	350	Jun 2019
Battery storage	Kennedy Energy Park – Phase 1 – Storage	2 MW / 4 MWh	Oct 2018

6.3 South Australia

The 2018 ESOO projects:

- The forecast risk of USE over the next four years is low, with USE within the reliability standard. This assessment does not include the impact of the temporary generators which are 'out-of-market' and are therefore not modelled. Nor does it consider the potential for, or impact of, pain sharing with Victoria.
- The ESOO assumes that all generator availability is provided to the market unless a unit is on an unplanned outage. The current MT PASA offers in South Australia for next summer are approximately 250 MW lower than the total summer capacity modelled in the 2018 ESOO. A sensitivity which withdraws 250 MW from South Australia this summer results in a large increase in USE across both South Australia and Victoria, and puts both regions at high risk of exceeding the reliability standard.
- The staged retirement of Torrens Island A, beginning in 2019, is initially balanced by the entry of the Barker Inlet Power station. As the third and fourth units retire in 2020 and 2021 respectively, the level of USE in South Australia is projected to begin increasing.
- In the absence of new investment, the reliability standard is projected to no longer be met by 2024-25 in the Neutral scenario, and by 2022-23 in the Fast change scenario. The reliability standard is expected to be met in the Slow change scenario.
- South Australia shares a forecast reliability gap with Victoria, with a gap of 40 MW across the two regions from 2022, increasing to 460 MW by 2028, with most USE projected to occur in summer between 6.00 pm and 8.00 pm.

6.3.1 Generation and storage changes

There are 469 MW of committed large-scale wind and solar generation projects in South Australia, listed in Table 17.

The 2018 ESOO also includes the staged withdrawal of Torrens Island A (480 MW) between 2019 and 2021, and its replacement with the Barker Inlet Power Station (210 MW) in 2019.

Table 17 New committed generation and storage in South Australia

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Bungala Two Solar Farm	110	Nov 2018
	Tailem Bend Solar Farm	108	Winter 2019
Large-scale wind	Willogoleche Wind Farm	125	Winter 2018
	Lincoln Gap Wind Farm – stage 1	126	Apr 2019
Natural gas	Barker Inlet Power Station	210	August 2019

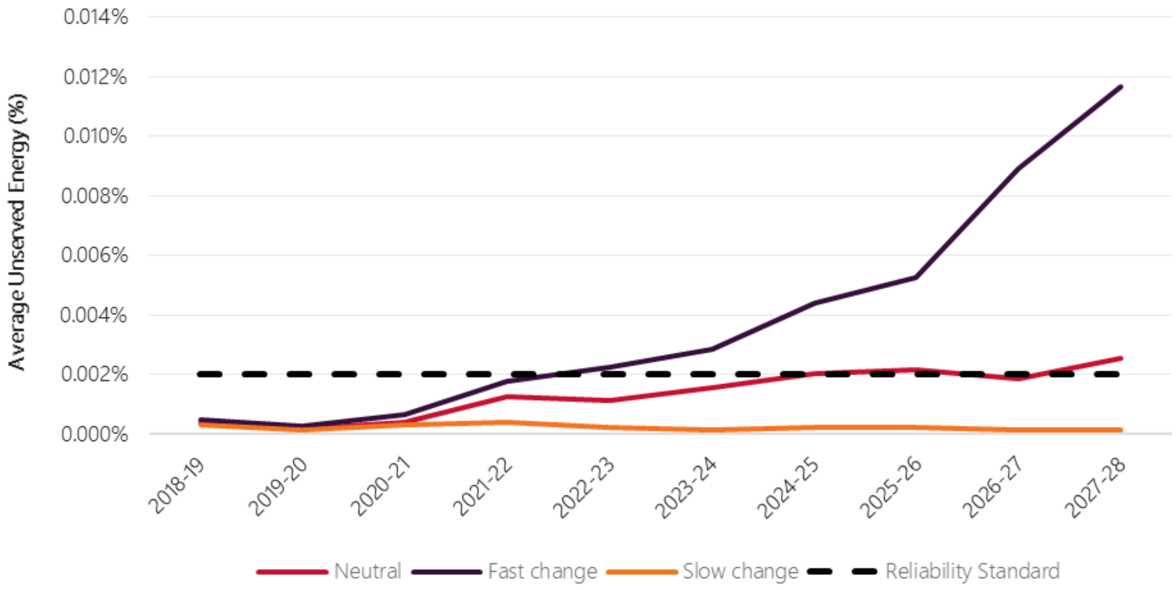
6.3.2 Supply adequacy assessment

Figure 35 shows the projected level of USE for the Fast change, Slow change, and Neutral scenarios. These scenarios assume only committed generators enter the market over the ESOO timeframe. Forecast USE is within the reliability standard over the next three years. The retirement of the fourth Torrens Island A unit in 2021 results in an increase in forecast USE, which continues to rise as forecast peak demands increase across Victoria and South Australia.

The reliability standard is forecast to be met in the Slow change scenario. The level of USE is forecast to exceed the 0.002% standard by:

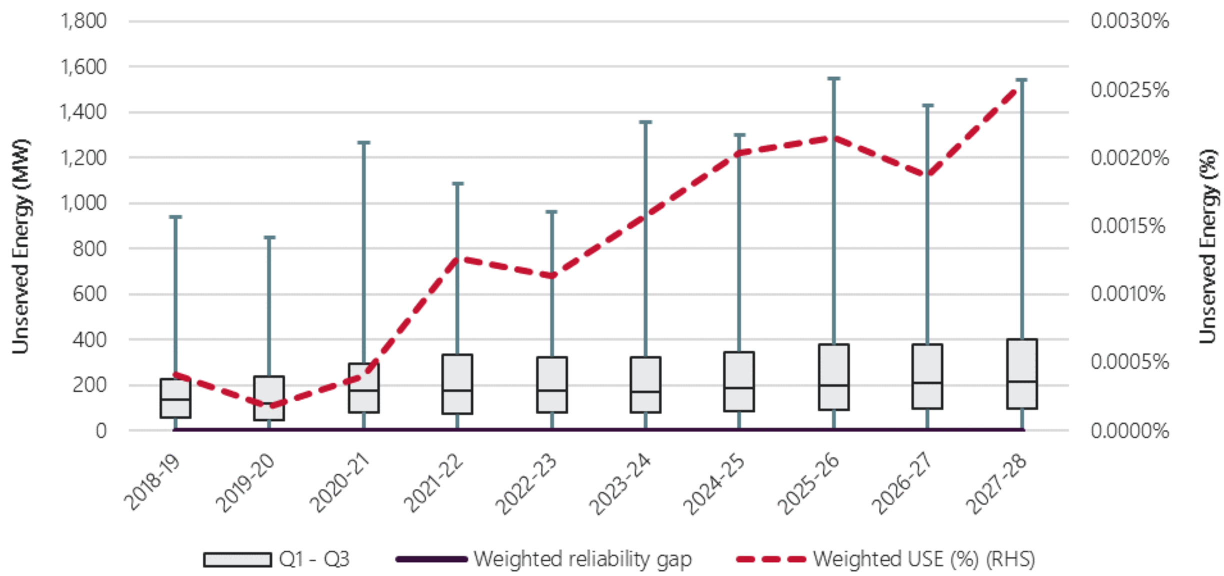
- 2022-23 in the Fast change scenario.
- 2024-25 in the Neutral scenario.

Figure 35 Forecast USE outcomes, South Australia, existing and committed projects only



The size of USE events in South Australia is forecast to grow slowly over the modelling timeframe as the expected level of USE increases, as shown in Figure 36[68].

Figure 36 Forecast size of USE events, South Australia, Neutral, committed projects only (10% POE events)



[68] As previously stated, the reliability gap is shared between Victoria and South Australia. No reliability gap is shown in this figure, because the additional capacity required to meet the weighted reliability standard in Victoria is sufficient to also reduce South Australian USE to below the reliability standard.

Over the next three years, the USE events tend to be small, with the majority of USE periods below 300 MW. By 2028, 25% of the forecast USE events are in excess of 399 MW. To help put this in perspective, 200 MW of USE in South Australia is equivalent in scale to 100,000 households being without power for an hour, although households are not necessarily the consumer segment that would first shed load.

In the ISP development plans, the commissioning of the RiverLink interconnector between New South Wales and South Australia coincides with some withdrawal of GPG. This capacity is replaced in the ISP plans, as shown in Table 18.

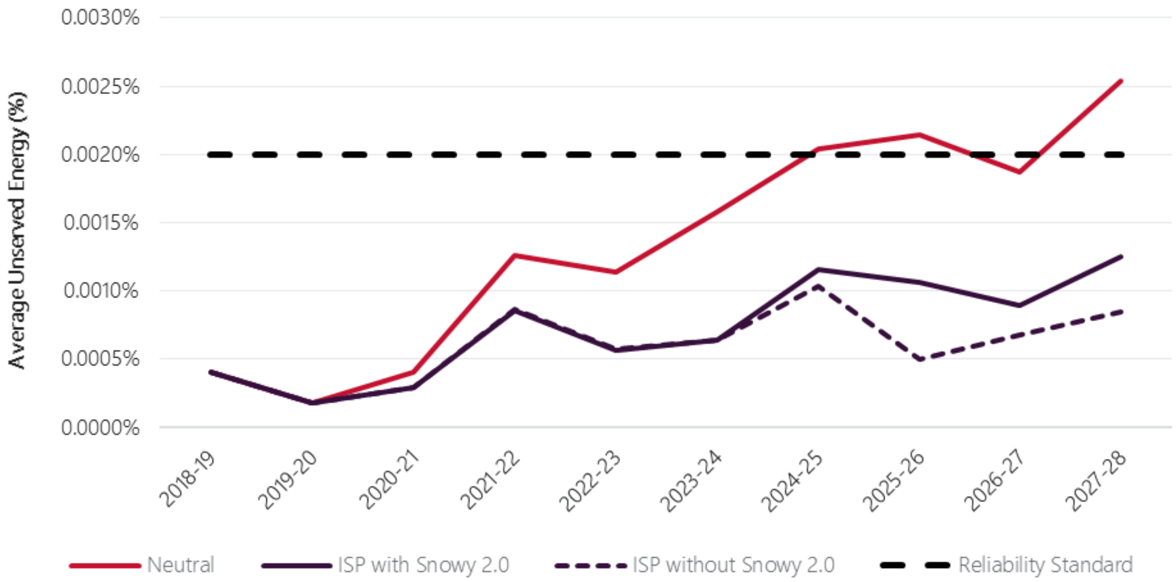
Table 18 ISP developments in South Australia (over and above committed) by 2028

Source	Capacity (MW)	ISP Plan
Utility-scale storage	649	Without Snowy 2.0
	233	With Snowy 2.0
Additional wind and solar generation in South Australia	975	Without Snowy 2.0
	230	With Snowy 2.0
Additional interconnection with New South Wales	750	Both development plans
Additional interconnection with Victoria[A]	100	Both development plans

A. Due to the transmission works associated with the RiverLink augmentation

Despite the reduction in dispatchable capacity located in South Australia, both ISP development plans are projected to deliver improved reliability outcomes compared to the core ESOO Neutral scenario, resulting in USE below the reliability standard, as shown in Figure 37.

Figure 37 Forecast USE outcomes, South Australia, ESOO vs ISP development plans



6.4 Tasmania

The 2018 ESOO projects a negligible level of USE across all scenarios in Tasmania, which has a significant surplus in generation capacity, although this is limited at times due to reservoir storage levels. The resilience of Tasmania to rainfall conditions is analysed in AEMO's EAAP.

6.4.1 Generation changes

There are 256 MW of committed large-scale wind projects that have met AEMO's commitment criteria in Tasmania, as listed in Table 19.

Additionally, Tamar Valley CCGT is unavailable over the ESOO horizon, based on information provided by Hydro Tasmania.

Table 19 New committed generation and storage in Tasmania

	Project	Capacity (MW)	Commercial operation date
Large-scale wind	Granville Harbour Wind Farm	111.6	Summer 2019-20
	Wild Cattle Wind Farm	144	Dec 2019

6.5 Victoria

The 2018 ESOO projects:

- Without action to procure additional reserves, the risk of load shedding would remain high for this summer, with Victoria at risk of exceeding the reliability standard in 2018-19.
- USE declines slightly over the following two years, due to flat peak demand projections and an increase in renewable generation.
- As forecast peak demands increase, the level of USE starts to rise. In the absence of new investment, the reliability standard is no longer met by 2021-22 in the Neutral and Fast change scenarios. The reliability standard is expected to be met in the Slow change scenario.
- Victoria shares a reliability gap with South Australia, with a gap of 40 MW across the two regions from 2022, increasing to 460 MW by 2028, with most USE occurring in summer between 4.00 pm and 7.00 pm.

6.5.1 Generation changes

There are 1,903 MW of committed large-scale wind and solar projects and 75 MW of large-scale battery storage projects in Victoria, summarised in Table 20.

Of this total, 1,448 MW of additional wind and solar projects have met AEMO's commitment criteria in the last quarter, highlighting the rapid rate of development in the region.

Table 20 New committed generation in Victoria

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Gannawarra Solar Farm	50	Winter 2018
	Bannerton Solar Park	88	Sep 2018
	Wemen Solar Farm	87.75	Oct 2018
	Karadoc Solar Farm	90	Summer 2018-19
	Yatpool Solar Farm	81	Winter 2019
Large-scale wind	Mt Gellibrand Wind Farm	66	Winter 2018
	Lal Wind Energy Facility – Elaine end	79	Dec 2018
	Moorabool Wind Farm	320	April 2019
	Crowlands Wind Farm	79.95	Winter 2019
	Murra Warra Wind Farm – stage 1	225.7	Winter 2019
	Bulgana Green Power Hub – Wind Farm	204	Winter 2019
	Stockyard Hill Wind Farm	532	Dec 2019
Battery storage	Ballarat Energy Storage System	30 MW / 30 MWh	Summer 2018-19
	Gannawarra Energy Storage System	25 MW / 50 MWh	Summer 2018-19
	Bulgana Green Power Hub – BESS	20 MW / 34 MWh	Winter 2019

6.5.2 Supply adequacy assessment

Figure 38 shows the projected level of USE for the Fast change, Slow change, and Neutral scenarios. These scenarios assume only committed generators enter the market over the ESOO timeframe.

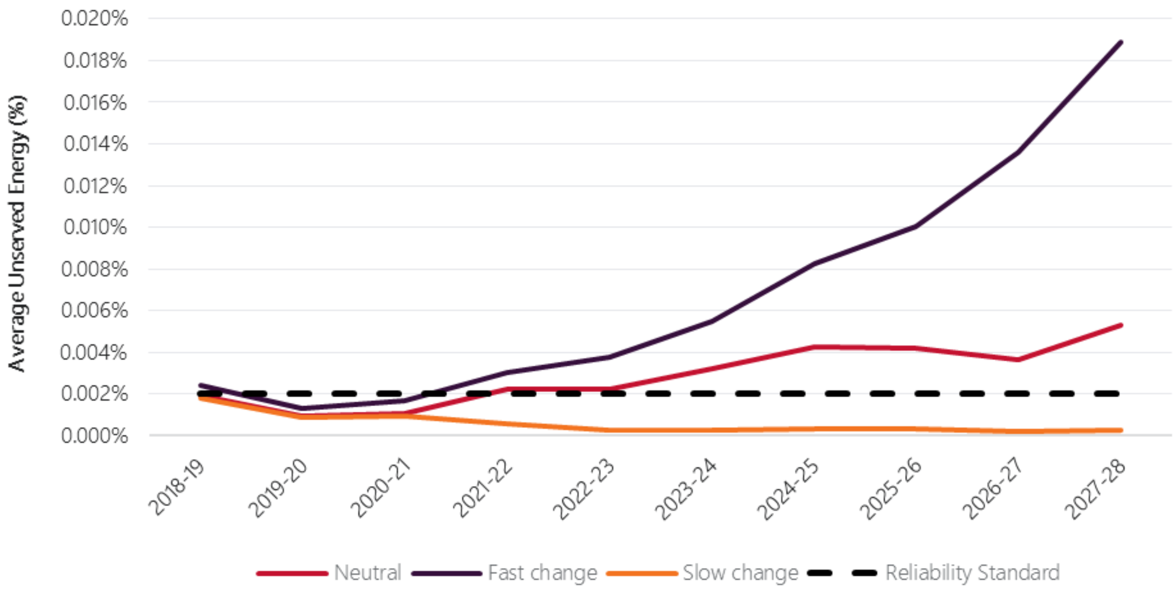
Although USE risks are projected to be high in 2018-19, if no additional reserves are procured, forecast USE remains within the reliability standard over the next three years. The level of forecast USE declines following this summer, due to the projected impact of additional renewable generation and battery storage, although small changes in either supply or demand forecasts could materially change this reliability outlook.

In the absence of new investment, the level of USE is forecast to exceed the 0.002% standard by:

- 2021-22 in the Fast change scenario.
- 2021-22 in the Neutral scenario.

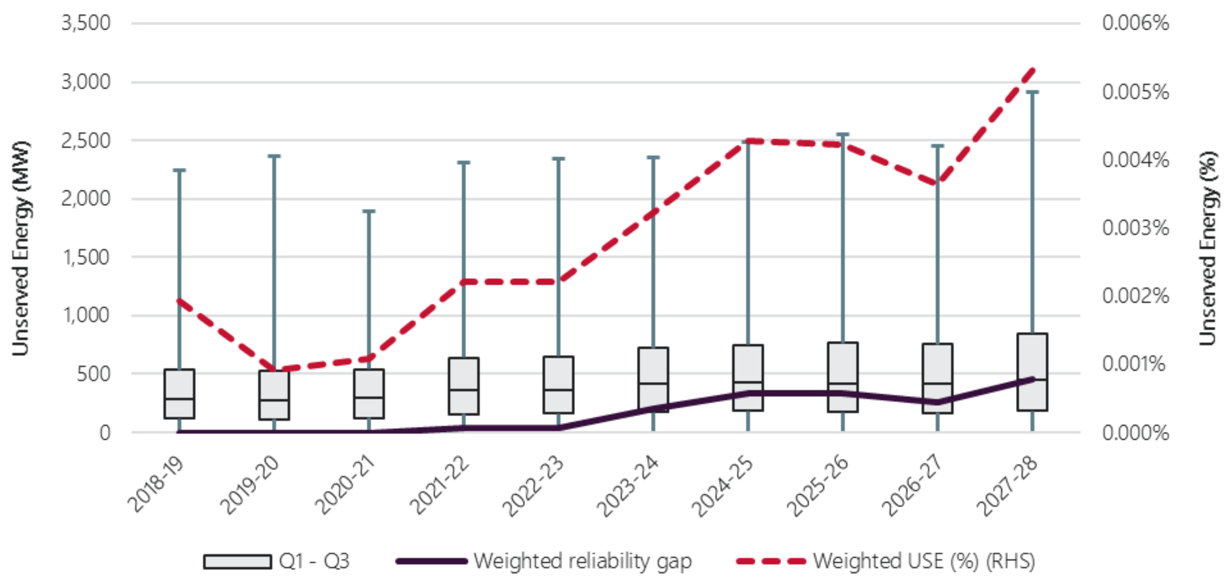
The standard is forecast to be met in the Slow change scenario.

Figure 38 Forecast USE outcomes, Victoria, committed projects only



Over the next three years, the size of USE events is forecast to remain relatively constant, as Figure 39 shows. Approximately 75% of USE events are below 539 MW over this period. To help put this in perspective, 500 MW of USE in Victoria is equivalent in scale to 250,000 households without power for an hour, although households are not necessarily the consumer segment that would first shed load. As with other regions, as the expected level of USE starts to rise, the size of forecast USE events also increases, and 25% of USE events are above 847 MW by 2028.

Figure 39 Forecast size of USE events, Victoria, Neutral, committed projects only (10% POE USE events)



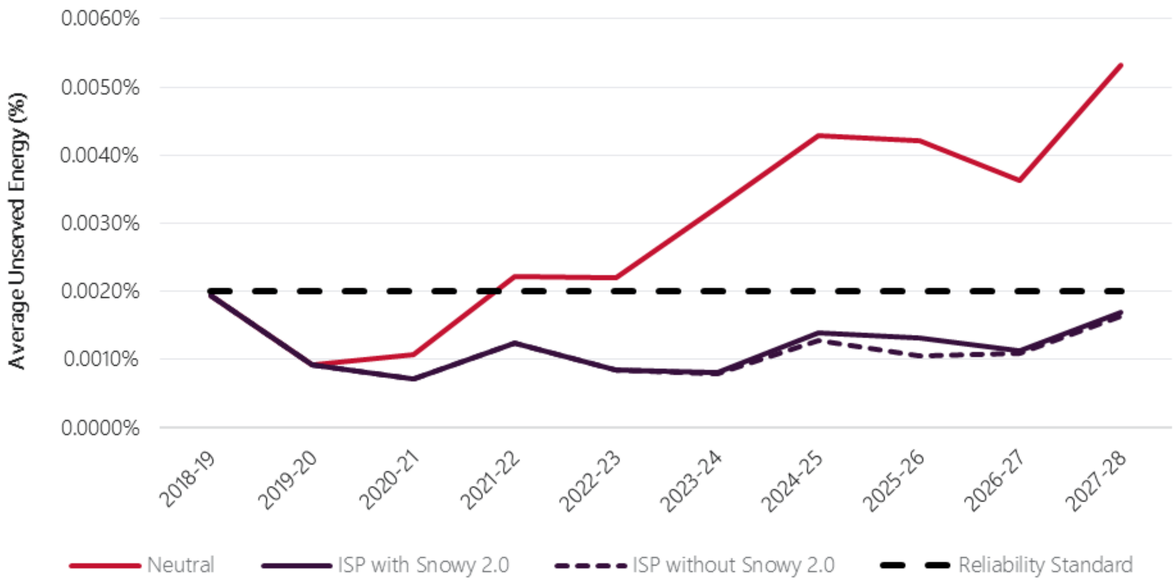
Under the ISP sensitivities, over 5.4 GW of wind and solar generation is forecast to be constructed in Victoria by 2028, largely due to the impact of the VRET. The development of generation and transmission in the ISP that reduces USE below the levels observed in the ESOO scenarios is shown in Table 21.

Table 21 ISP developments in Victoria (over and above committed) by 2028

Source	Capacity (MW)	ISP plan
Gas-powered generation (GPG)	0	Without Snowy 2.0
	90	With Snowy 2.0
Additional wind and solar generation in Victoria	3,625	Both development plans
Additional interconnection with South Australia	100	Both development plans

Despite the lack of any sizeable increase in dispatchable capacity, the level of USE in Victoria is forecast to fall to be within the reliability standard under both ISP development plans. This is due to the substantial volume of additional new intermittent generation developed in Victoria to meet the VRET, combined with the ability to import additional reserves from New South Wales via the RiverLink interconnector, in the ISP plan. The USE outcomes under the ISP sensitivities are shown in Figure 40.

Figure 40 Forecast USE outcomes, Victoria, core ESOO vs ISP development plans



7. Investment landscape

The ESOO results highlight potential reliability gaps in the NEM over the next 10 years, and illustrate the need for an investment environment that is capable of incentivising investment in a portfolio of generation resources, storage, DER, demand response, and transmission in a timely manner. Government and industry must actively work towards creating the landscape for this to occur, without disruption to reliability, and at the lowest cost to consumers.

The ESOO emphasises that without additional investment in generation capacity to replace the retirement of existing generators reaching the end of their technical life, a reliability gap is emerging and projected to increase in Victoria, New South Wales, and South Australia. While the current investment profile is encouraging, it may not secure adequate supply with the right technical characteristics to ensure reliability is maintained over the long term.

The analysis reaffirms the soundness of the decision to reinstate long-notice RERT earlier this year as a safety net for AEMO to manage supply scarcity risks in the short term if market response is not sufficient. It also highlights the need for policy and regulatory arrangements, such as those contemplated by the reliability mechanism of the National Energy Guarantee, to provide the right signals for investment in supply and demand resources that can help ensure dispatchability in all hours.

With this ESOO, AEMO aims to further inform a transparent and evidence-based approach to understanding, anticipating, and adapting to the variety of risks and future solutions being explored to support the ongoing development of the NEM. In conjunction with the Energy Security Board, Reliability Panel and industry, AEMO is working to identify proactive policy, regulatory, and market reforms that may be required to facilitate future energy investment.

This 2018 ESOO promotes further development of the following issues:

- Designing a coordinated and timely approach to transmission planning and development, that supports positive consumer outcomes during the energy transition as promoted in AEMO's inaugural ISP.
- Promoting the market design changes and enduring policy certainty contemplated in the Finkel *Blueprint for the Future* Security of the NEM[69], the AEMC's Reliability Frameworks Review[70], and the reliability mechanism of the National Energy Guarantee, that is needed to support efficient, technology-neutral investment decisions in dispatchable resources and DER that achieve targeted emissions levels while maintaining system reliability. AEMO will contribute to processes designed to establish changes in approaches to ensure sufficient resources are developed to meet emerging reliability requirements.
- Continuing to work with the Reliability Panel on the appropriateness of the current reliability standard in the face of an increasingly 'peaky' supply-demand balance. The installation of high levels of embedded solar PV generation across the NEM is leading to a later and shorter peak in operational demand. Concurrently, the USE measure is becoming more sensitive to weather-driven variations in input assumptions. With increasing growth in variable renewable energy resources, both demand and supply are now exposed to the vagaries of weather, such as temperature and wind and solar generation availability, impacting AEMO's ability to meet demand on extreme peak days.

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[69] *Independent Review into the Future Security of the National Electricity Market*, June 2017 available at https://www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market.

[70] See https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review.

- Developing an integrated strategy for DER, considering operational processes, standards, integration processes, market frameworks, data visibility, and network incentives to more effectively manage market conditions while maximising DER potential. For instance, by 2028, market mechanisms to facilitate greater levels of DER coordination could provide up to 500 MW of additional supply at times of high demand across regions, based on the levels of behind-the-meter battery installations and default levels of aggregation assumed in this ESOO analysis.
- Investigating emerging operational reliability[71] challenges and issues in the NEM. This work includes consideration of the changing nature of reliability risks, and suitability of existing standards, processes, and procedures to manage these risks into the future. AEMO will soon publish a short paper on its observations to date to further inform discussions regarding reliability risks and standards requirements in the NEM.
- Improving the accountability, transparency, and quality of demand and supply forecasting to help inform decision-making. AEMO will continue to work with stakeholders and through the Forecasting Reference Group[72] to improve demand forecasts and will closely monitor actual supply to the market to ensure reliability modelling closely represents performance. AEMO will propose a range of demand and supply forecast accuracy measures, engage with experts and consult with stakeholders to develop a set of measures by December 2018. Preliminary thinking on these measures is documented in Appendix A1.

Collectively, actions in these areas can simultaneously identify required and likely investments, provide pathways for orderly retirements and investment in new resources that can best meet economic objectives, and enable broad innovation through the removal of existing and emerging barriers to entry and competition.

[71] Operational reliability refers to the management of supply and demand over operational timeframes (days, hours, minutes).

[72] See http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Forecasting-Reference-Group for more information.

A1. Monitoring forecasts

Measuring and improving forecast accuracy is vital for AEMO to provide independent, reliable, and accurate advice to stakeholders of the NEM. Internally, AEMO assesses forecast accuracy as part of a continued improvement process to measure actual performance against forecasts, identify and eliminate systemic bias, incorporate new sources of relevant information that add explanatory power, and develop innovative methods to improve the accuracy of both the data collation and forecasting model process.

Previous forecast accuracy assessments have focused on the performance of singular variables, such as point estimates of maximum demand as a primary driver of system reliability. The inclusion of a wider variety of generation sources and changing demand dynamics has motivated the need to assess the performance of reliability as a distribution of outcomes, rather than point estimates alone. A key priority has been to increase the sophistication of internal forecast accuracy assessments, without unneccessarily increasing complexity. This will allow users with a range of technical capabilities to properly assess AEMO's forecasting performance.

Forecasting accuracy assessments are disaggregated to individually measure distributional estimates of annual consumption, maximum demand, minumum demand, and generation capacity. The forecast accuracy assessment therefore prioritises the need to measure accuracy in demand and supply inputs, as well as in the forecasts themselves.

A range of leading and lagging indicators to assist with predictive analysis are also being developed, to better understand the dynamics of less certain developments in rapidly evolving aspects of the NEM, such as battery installations and electric vehicle uptake.

These developments will drive continued improvement in understanding the distribution dynamics of consumption and supply, and augment existing methods with behavioural models to better assess future reliability.

User requirements for a revised forecasting monitoring system that incorporates the above measures will be consulted on, and the scope finalised, by the end of 2018, with formal delivery by mid-2019. AEMO will increase the availability of assessments of accuracy, and will continue to welcome feedback to further improve performance.

A key element of the forecast accuracy assessment process is the use of AEMO's existing stakeholder engagement forums (such as the Forecasting Reference Group), as well as other industry forums. These are needed to improve the quality of inputs, develop more robust modelling processes, obtain valuable feedback, and ensure the appropriate validation and quality control of outputs. It is vital that AEMO's approach to forecasting is comprehensive and aligned with industry best practice to allow efficient and reliable decision-making in future energy investments over both the short and long term.

The assessment process for individual elements comprising aggregated reliability forecasts is defined in the following sections.

A1.1 Annual consumption forecasts

AEMO began producing internally-generated forecasts in 2012, with the inaugural publication of the 2012 *National Electricity Forecasting Report* (NEFR). Before that, forecasts were aggregated from information provided by TNSPs. Since the 2012 publication, a number of improvements to the forecasting process have been implemented:

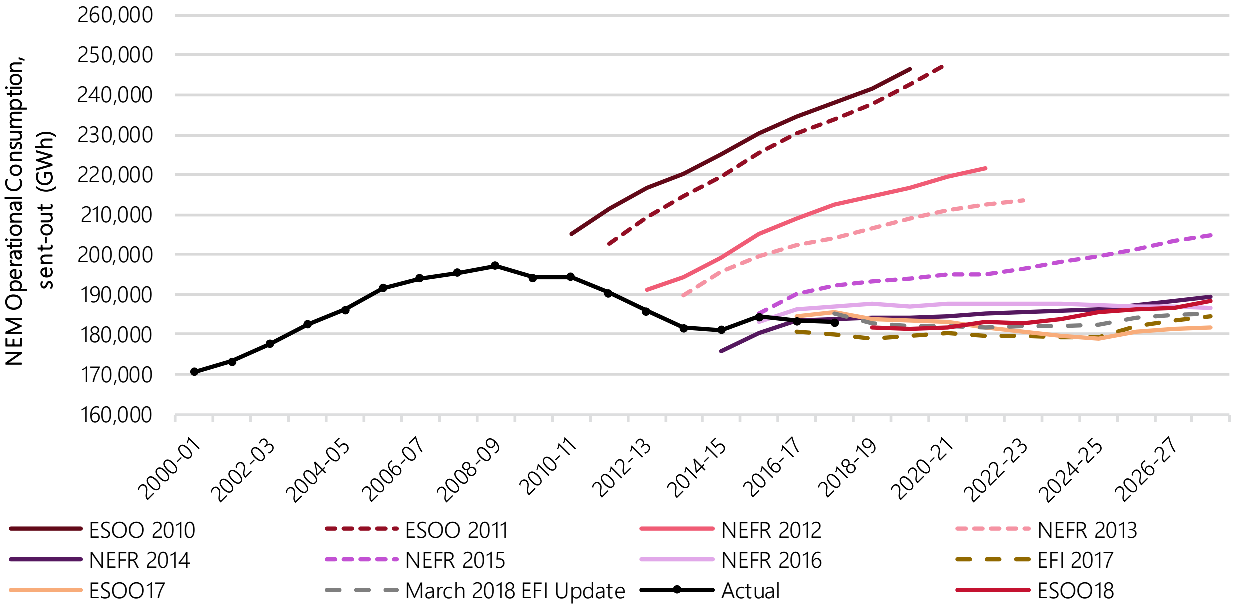
- Beginning with the 2012 ESOO, forecasts of energy efficiency impact and rooftop PV uptake were included, reducing forecast consumption compared to previous years. Subsequent refinements of these component forecasts have helped bring the regional forecasts more in line with observed trends.
- From 2016, the process segmented electricity usage into business and residential sectors. AEMO has also expanded its survey and interview process to obtain consumption patterns of large industrial users of energy. This has improved the quality of the business sector forecast, reflecting the structural shift from energy-intensive manufacturing industries toward a service-based economy.

The latest series of forecasts considers the introduction of electric vehicles, behind-the-meter batteries, and small non-scheduled PV systems. These are expected to affect consumption patterns, particularly over the longer term.

Figure 41 illustrates the change in operational demand (as sent-out) forecasts produced by AEMO over the past six years. As AEMO has incrementally improved the quality of consumption forecasts for the NEM, so has the accuracy of these results improved. Continued enhancements to consumption forecasts are under development to further account for changing drivers in the way in which Australians use electricity.

Further enhancements may also include reporting on forecasting performance for business and residential sectors, and DER, separately, to the extent that historical data is available for comparison. Sectorial forecast performance monitoring will help AEMO focus future improvements in areas most likely to make a material difference to forecast accuracy.

Figure 41 Operational consumption forecasts versus actual, 2010-18



A1.2 Maximum and minimum demand forecasts

Each year AEMO provides a forecast accuracy report on the demand forecasts produced in the ESOO. Forecast accuracy for both minimum and maximum demand is important for the promotion of transparency and accountability of reliability in the NEM. Accurate forecasts of the extremes in demand are vital for planning and investment in future energy sources, transmission and distribution. This year's forecast accuracy report will be published by 1 November 2018.

Minimum and maximum demand are reported as probabilistic forecasts, representing the full distribution of demand. As discussed in Section 3.2.1, maximum demand forecasts are approximately 10% higher under 10%

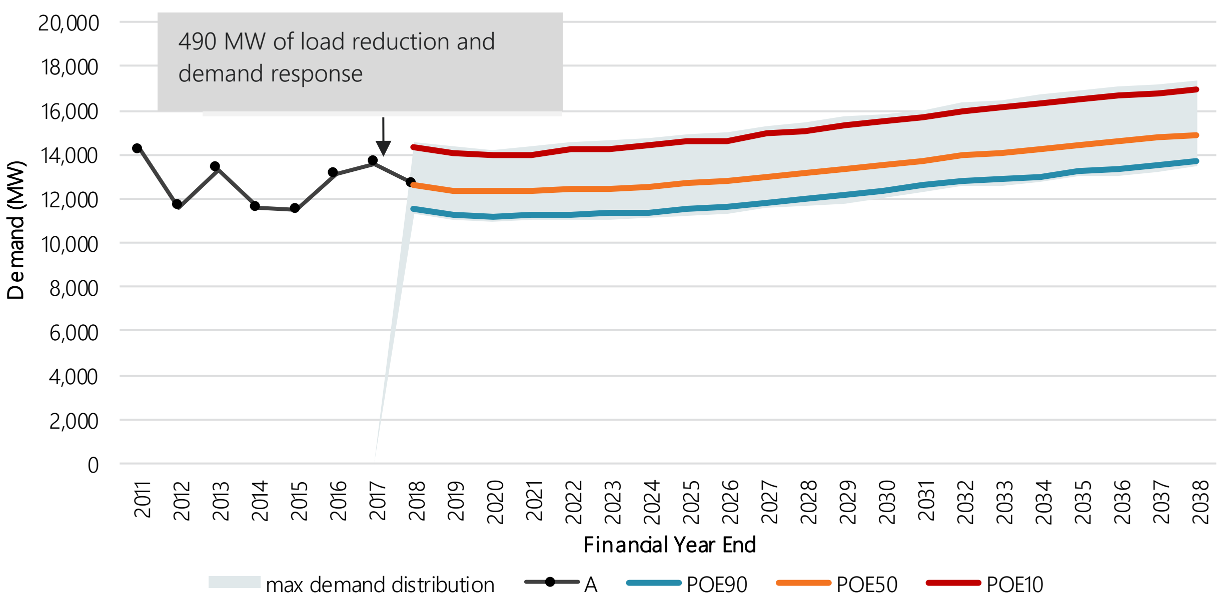
POE conditions than the forecast under 50% POE conditions. Between 5% POE and 95% POE conditions, the maximum demand may vary by more than 30% from the lower bound to the upper bound.

For example, Figure 42 shows New South Wales' maximum demand distribution for the 2018 ESOO demand forecast, and compares the distribution to the last eight years of historical maximum demand observations, readjusted to account for any load reduction and demand response that may have occurred.

New South Wales' demand may vary by 3,300 MW between the lower bound (95% POE) and the upper bound (5% POE). Some of this variance may be due to temperature, solar irradiance impacting rooftop PV generation, battery charge/discharge, large industrial load movements, business load, day of the week, or holiday impacts, while some may be due to unobservable random consumer behaviour. As minimum and maximum demand, by definition, are outliers (that is, the maximum of the maximum, or the minimum of the minimum), this random consumer behaviour can introduce variance up to roughly 5% of the maximum demand.

Capturing and justifying this element of the forecast is increasingly vital to assess forecasting performance in the future,[73] particularly when a maximum demand forecasting error of less than 5% can be the difference between the reliability standard being exceeded in a region or no USE being observed at all.

Figure 42 New South Wales, maximum demand distribution forecast vs historical demand



It is difficult to measure the accuracy of probabilistic forecasts, especially where they relate to the 'long tail' of distributions. The measures adopted as part of AEMO's forecasting performance monitoring system are therefore likely to require specially developed techniques.

73 AEMO's forecast accuracy report, to be published in November 2018, will examine the drivers leading to minimum and maximum demand events to compare forecast verses actual, noting that not all variation can be explained by the demand drivers.

A1.3 Analysis of available capacity

Methodology for modelling the capacity and availability of dispatchable generation

The approach to modelling available capacity in the 2018 ESOO was as follows:

- Summer and winter capacities for generation units are provided by participants through submissions to AEMO's Generator Information Survey for the following 10 years[74]. The summer capacity provided by generators represents the available capacity of each generator during ambient local weather conditions at times of 10% POE regional peak demand.
- Summer capacities are used from November until March inclusive for mainland NEM regions, and December until March inclusive for Tasmania.
- Calculated outage parameters for full and partial outages in the 2018 ESOO were based on data provided by participants in annual surveys.
- These inputs were provided to a market simulation that randomly generated full and partial outages over the forecast horizon for each generating unit. Unique outage patterns were generated for every simulation, including for each simulated reference year. Simulating many outage patterns ensures that a range of availability outcomes due to random forced outages is properly captured, to avoid statistical bias in the results produced.

Forced outages exclude planned or strategic withdrawals of available capacity. An outage (including full outage, partial outage, or a failed start) is considered "forced" if the outage cannot reasonably be delayed beyond 48 hours. The forced outage rates of thermal and hydro generation used in the 2018 ESOO were calculated using information sourced by participants up to March 2018. This data was then aggregated, based on fuel sources and in some instances, the state in which generation is located. Parameters calculated included a full outage rate, a partial outage rate with a level of derating, and a mean time to repair.

In addition to having updated data based on 2017-18 outcomes, a number of methodological changes have been made compared to the 2017 ESOO with regards to outage modelling:

- Change in aggregations – due to an observed divergence in the reliability trend between New South Wales and Queensland black coal, the black coal aggregation has been split by region.
- For a number of technology aggregations, there has been a clear deterioration in reliability over the period where data is available. To reflect more realistic expectations of generator performance, AEMO has used only the most recent three years of outage data for brown coal, black coal, and gas-fired steam turbines.

Methodology for assessing veracity of modelling inputs

Outage parameters are particularly important in reliability studies such as the ESOO and MT PASA, given that they are commonly seen as a key driver in periods where USE is observed. As such, it is appropriate to determine whether the capacity available from scheduled generation in the 2018 ESOO modelling provides an appropriate measure of the capability, compared to actual scheduled generation in the NEM, so the data provided, and the way it is used, reflects actual market outcomes.

This may be accomplished through a comparison between ESOO simulations and historical observations during extreme demand periods.

The methodology behind this comparison involved:

- Extracting from history the 10 days with the highest demand over a given financial year for each region. Availability data was then taken from these days in the 2.00 pm to 8.00 pm time period. This selection of historical data was used because generators are expected to have greater incentive to make available energy at their full capacity during these high demand periods. Units with availability below their listed

[74] AEMO Generator Information Survey is published regularly at the following address: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-informationto satisfy clause 3.13.3(q) of the National Electricity Rules. Market participants are required to provide this information to AEMO under clause 3.13.3(t).

seasonal availability during these periods were assumed to be experiencing a partial or full outage, rather than a strategic withdrawal of capacity. Two sets of historical observations were considered for this analysis, the financial years 2016-17 and 2017-18.

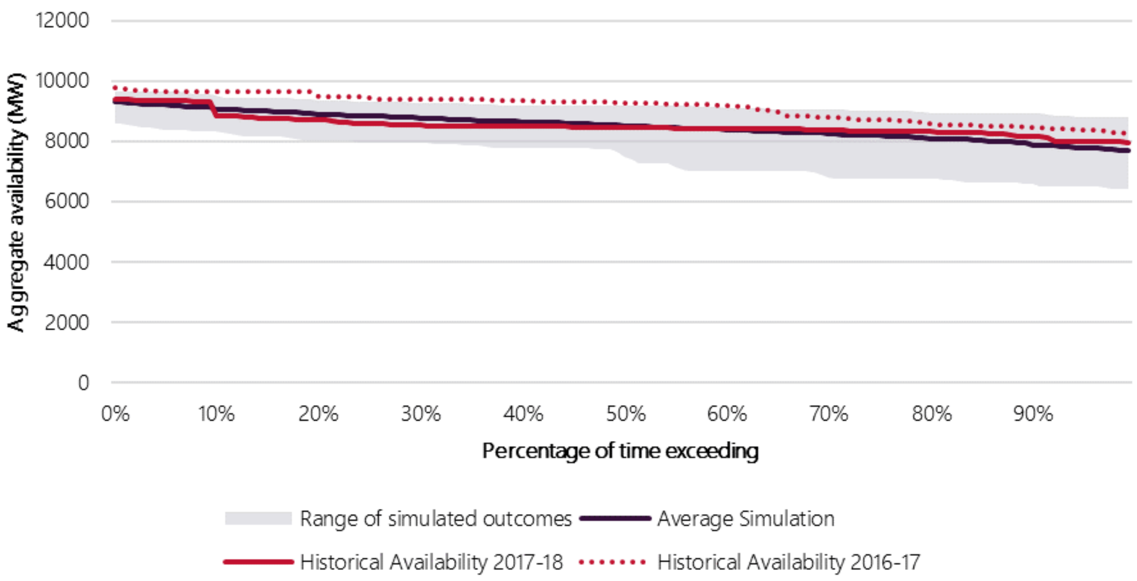
- Extracting availability data from 10 summer days of an ESOO model with 100 random outage samples, then taking simulated availability data from these days in the 2.00 pm to 8.00 pm time period.
- Aggregating historical and simulated data with respect to their fuel types and regions, plotting duration curves comparing the data sets, and cleaning historical data such that only units operating in the forecast were considered.

There are a number of limitations to this approach that need to be considered when assessing outcomes:

- The generator capacities are provided based on ambient weather at the time of 10% POE peak demands. By definition, periods with demand at this level, and therefore the weather conditions that drive them, are rare. It is expected that, in most cases, historical periods would have temperatures below the level associated with a 10% POE peak. As such, it is likely that some generators will have a higher capacity than the capacity simulated, due to lower historical temperatures.
- The historical data provides a relatively limited dataset, so would at times be expected to be materially different from the average of simulations due to statistical variability. The level of variability observed across simulations over these relatively short periods of interest is provided in the following figures.

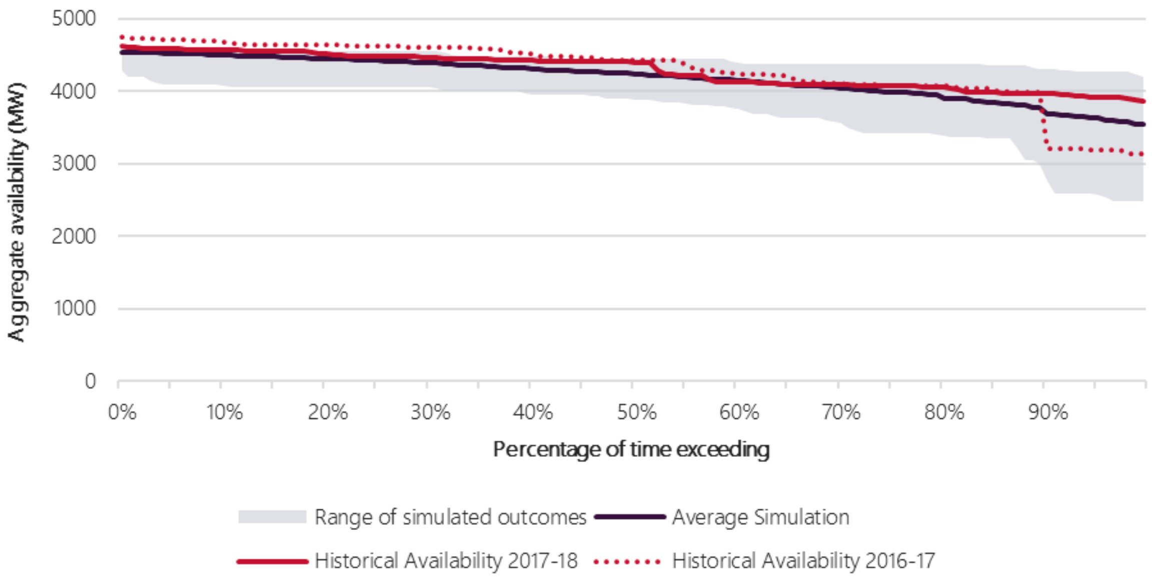
The results in Figure 43 show the comparison for black coal generation in New South Wales in 2016-17 and 2017-18. The historical availability in 2016-17 was above the simulation average and tended towards the upper limit of simulated outcomes, while in the 2017-18 financial year, the historical availability during the observed periods closely resembled the average simulation.

Figure 43 Historical and simulated available capacity comparison, black coal-fired generators, New South Wales



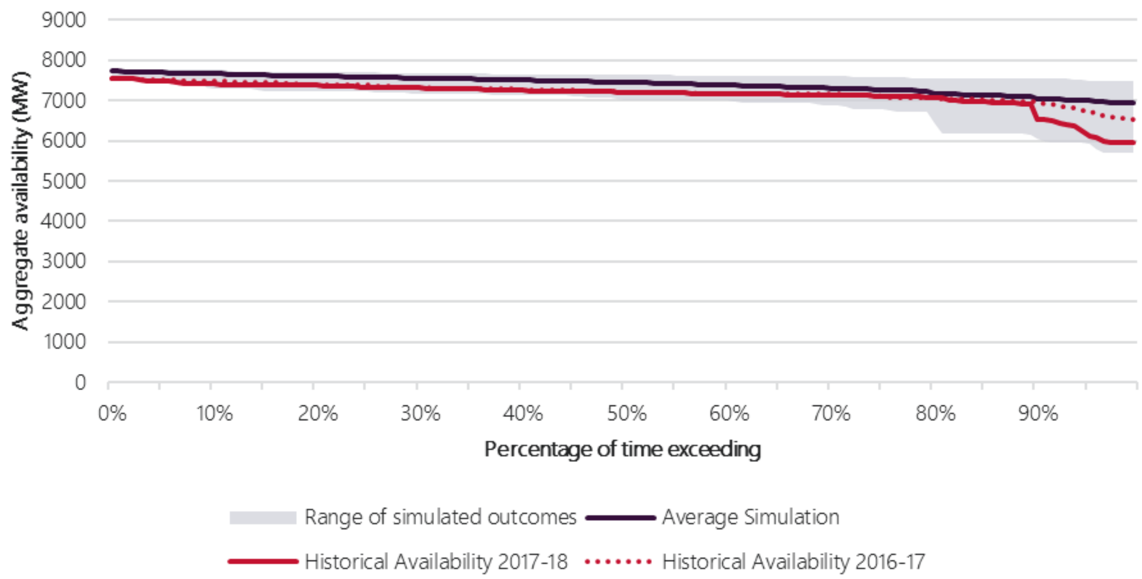
For Victorian brown coal generation, Figure 44 below shows that across both financial years the simulated capacity is generally lower than the historical capacity, with the exception of one day during the 2016-17 financial year. AEMO's analysis indicates that on this day in 2016-17, multiple units were simultaneously on forced outage. It is important to note that credible events such as multiple forced outages are also captured in AEMO's simulations, and that these lower availability values fall within the range of simulated outcomes.

Figure 44 Historical and simulated available capacity comparison, brown coal-fired generators, Victoria



In Queensland, the historical availability of coal generators is seen in Figure 45 to be towards the lower end of the range of simulated outcomes in both financial years. The historical market conditions in Queensland are believed to be a material contributing factor in this comparison. Since Queensland has a surplus of available capacity relative to demand compared with other states, there are periods where capacity is not offered as available, as it was not required, even during these high demand periods. Despite this, the historical observations of available capacity in Queensland are adequately captured within the range of simulations.

Figure 45 Historical and simulated available capacity comparison, black coal-fired generators, Queensland



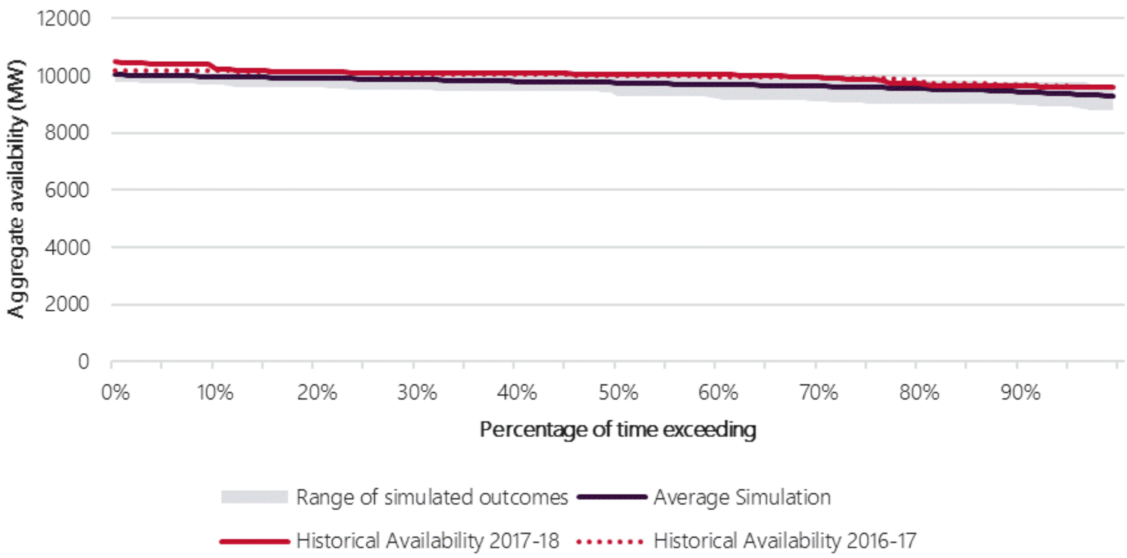
For gas-fired generators[75], the NEM has been considered in aggregate, because historical data is otherwise limited. As Figure 46 below shows, both financial years had historical availability that tended towards the

[75] This aggregation includes OCGTs, CCGTs, gas-fired steam turbines, and liquid-fuelled generation.

upper bound of the simulation range. Despite being towards the upper limit of the simulation range, the mean difference in the historical and average simulation availability is relatively small.

Furthermore, as already discussed, there is likely to be disparity between the maximum seasonal availability for a unit and the historical availability of the units. Seasonal availabilities are provided to AEMO with respect to certain reference temperatures. Consequently, several of the historical periods used in this analysis had high demand but were not necessarily experiencing temperatures corresponding to 10% POE peak demand conditions. This is likely contributing to an increase in capacity for some historical observations.

Figure 46 Historical and simulated available capacity comparison, gas-fired generators, NEM



The analysis above illustrates that there is not a systematic overstatement or understatement of plant availability and capacity in the ESOO modelling when a comparison is made with history during high demand periods. AEMO's range of modelling outcomes has also captured the lowest availabilities within the range of simulated outcomes. This shows that, although the average in some instances may be slightly higher, the summer deration and forced outage rate assumptions are robust enough that the outcome has still been captured over our simulations.

A1.4 Next steps

AEMO will continue to develop a range of demand and supply forecast accuracy measures, engage with experts and consult with stakeholders to develop a full set of performance measures by December 2018. It is important to note the difficulties in measuring the accuracy of probabilistic forecasts, especially where they relate to the 'long tail' of distributions. Increased volatility in the tail of the probabilistic distributions poses unique challenges in accuracy assessments. As a result, the forecast accuracy methodology is likely to require specially developed measures to capture these dynamics.

A2. Demand forecast details

A2.1 Annual consumption – regional overview

Regional forecasts all share the national trends and forecast dynamics that are discussed in Section 2, although each region has their own internal characteristics, which are discussed below. Data and charts for each region can be sourced from AEMO's forecasting data portal[76].

A2.1.1 New South Wales

New South Wales operational consumption is forecast to remain flat initially, due to continued fast uptake of rooftop PV offsetting growth in residential connections and business sector growth. As the rooftop PV installation rate is projected to decline in the medium term, forecast growth in operational consumption resumes. This is mainly driven by the business sector (both manufacturing and other business), along with electricity consumption associated with the uptake and use of electric vehicles in the longer term, with New South Wales forecast to have the highest penetration of electric vehicles in the NEM states by 2038.

Overall, New South Wales is expected to remain the region with the highest operational electricity consumption in the NEM to the end of the 20-year horizon.

A2.1.2 Queensland

Queensland has the highest total installed PV capacity in the NEM in absolute terms, and is forecast to experience strong continued growth in uptake of both rooftop PV and small non-scheduled PV systems (PVNSG)[77]. As a result, Queensland is forecast to remain the NEM region with the largest installed capacity of distributed rooftop PV systems by the end of the forecast horizon. The growth in PV capacity is forecast to offset much of the underlying growth projected in the residential and business sectors.

In terms of growth drivers, Queensland has the largest forecast percentage growth of residential dwellings in the next 10 years (20% increase or 350,000 new dwellings), increasing underlying residential consumption.

A significant driver for Queensland consumption in the medium term is the continued growth forecast for the CSG sector, with production expected to increase until 2023-24 as LNG projects ramp to full production[78].

Overall, despite underlying consumption being forecast to increase as the population and the economy grow, Queensland consumption growth is expected to remain relatively flat, due to the projected high amount of rooftop PV and PVNSG penetration in the state.

[76] Available at http://forecasting.aemo.com.au/.

[77] Small-scale solar PV with estimated installed capacity greater than 100 kW and smaller than 30 MW.

[78] Further detail on the expansion of the CSG sector, and the relationship with LNG and Australia's eastern and south-eastern gas markets, is provided in the *Gas Statement of Opportunities*, available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

A2.1.3 South Australia

Although the residential sector's underlying consumption of electricity is expected to increase, the forecast points to a decreasing amount being sourced from grid-connected generators, as more consumers install rooftop PV systems. Moderate growth is expected in business consumption in the medium term, mainly driven by the manufacturing and mining sectors.

Overall, South Australia's annual operational consumption is forecast to increase slightly in the medium term, but otherwise remain flat over the next 20 years, as underlying growth is forecast to be offset by projected growing penetration of rooftop PV and PVNSG.

A2.1.4 Tasmania

With limited forecast growth in rooftop PV, operational electricity consumption is forecast to increase slightly in the short term, driven by projected increased business consumption, mainly from the manufacturing sector. Longer term, the forecast is flat, as forecast weak population growth and economic growth in the state is projected to be offset by relatively slow forecast growth in installed PV capacity.

A2.1.5 Victoria

Victoria's residential sector is expected to show moderate growth of underlying electricity consumption in the next 10 years as population is forecast to increase. This forecast increase is projected to be greater than the offsetting effect of rooftop PV developments, resulting in forecast growth in grid-supplied electricity for this sector.

Positive business sector growth is forecast from both manufacturing and non-manufacturing sectors.

Victoria is also forecast to have the second highest penetration of electric vehicles in the NEM by the end of the outlook period, adding to the increase in forecast electricity consumption.

Overall, Victorian operational electricity consumption is forecast to grow, driven by strong population growth and business sector growth. In the Neutral scenario, this is projected to lead to Victoria eclipsing Queensland by 2037 as the second-largest electricity consuming NEM region, measured in operational consumption.

A2.2 Maximum demand – regional overview

A2.2.1 New South Wales

Maximum operational demand is expected to remain relatively flat until 2021-22, then increase through to the end of the forecast period.

In the short term, high rooftop PV uptake is forecast to offset projected growth in connections and appliance uptake.

In the long term, maximum operating demand is expected to shift to later in the day, resulting in lower solar irradiance at the time maximum demand is likely to occur. This in turn is projected to result in rooftop PV no longer offsetting the primary growth drivers. Forecast growth in connections and electric vehicles is expected to cause maximum demand to grow over the 10- to 20-year horizon.

Relative to the March 2018 EFI Update, improvements in the energy efficiency of cooling appliances are assumed to be lower at the time of maximum consumption, limiting its dampening effects on maximum demand.

A2.2.2 Queensland

Queensland has the highest rooftop PV and PVNSG uptake relative to demand, with relatively high solar irradiance throughout the year. Queensland's maximum demand currently occurs in the afternoon, earlier than most other regions but, with high projected PV uptake, MD is expected to peak after sunset (on the balance of probabilities) by 2025-26.

Overall, maximum operational demand is expected to remain at current levels until 2025-26, as forecast high rooftop PV uptake is projected to offset growth in underlying demand in the residential and business (including CSG) sectors.

In the long term, without the offsetting impact from rooftop PV, the forecast increases in connections, business sector growth, and electric vehicles uptake are projected to drive moderate growth in forecast operational maximum demand over the 10- to 20-year horizon.

Relative to the March 2018 EFI Update, the improvement in energy efficiency of cooling appliances is assumed to be lower at the time of maximum consumption, thereby increasing maximum demand.

A2.2.3 South Australia

South Australia experiences maximum operational demand at around 8.00 pm in the summer months. At this time, the impact of rooftop PV and PVNSG is expected to continue to have little impact on maximum demand.

In the short term, operational maximum demand is forecast to experience slight growth, mainly driven by manufacturing, despite the South Australian Government's backing of the installation of 40,000 new battery systems over a four-year period, which is projected to have some dampening effect on grid demand during evening peaks.

In the long term, maximum operating demand growth is forecast to continue, driven by accelerating growth in electric vehicles and increased connections.

Relative to the March 2018 EFI Update, more growth is also assumed due to less improvement in the energy efficiency of cooling appliances at the time of maximum demand.

A2.2.4 Tasmania

Tasmania continues to experience its maximum demand in winter after sunset, due to heating load. As such, rooftop PV capacity has a limited impact on reducing maximum operational electricity demand in Tasmania.

In both the short and long term, growth in maximum operational demand in Tasmania is forecast to remain relatively flat, which is consistent with the March 2018 EFI Update.

A2.2.5 Victoria

Victoria is expected to experience slight growth in maximum operational demand until 2027-28, then experience higher growth through to the end of the forecast period.

In the short term, Victoria's forecast maximum demand for 2018-19 is broadly similar to the March 2018 EFI Update forecast, but will then experience slight growth to 2026-27, due to a forecast increase in connections coupled with a forecast decline in retail electricity prices, partly offset by projected growth in rooftop PV and PVNSG installations.

As the time of maximum operating demand shifts to later in the day, resulting in lower solar irradiance at the time maximum demand is likely to occur, projected increases in rooftop PV are no longer expected to offset the main growth drivers. Forecast growth in connections and the uptake of electric vehicles is projected to result in growth in maximum demand over the 10- to 20-year horizon. Relative to the March 2018 EFI Update, the energy efficiency of cooling appliances is assumed to be lower at the time of maximum consumption, increasing maximum demand.

A3. Probability of exceedance weightings

AEMO has historically calculated expected annual USE by using different levels of maximum demand outcomes, reflecting different underlying weather conditions that can drive extreme peak consumption. Assessments of USE consider the availability of supply to meet an uncertain demand, with many simulations conducted to account for potential generator outages.

Simulations, accounting for randomised generator outages, are generally limited to 10% POE and 50% POE maximum demand forecasts only, and the average of these simulations is weighted to account for the statistical spread of the spectrum of peak demands. Historically, it has been assumed that 90% POE and 50% POE USE outcomes are very close, so their weightings can be aggregated. Simulation of 90% POE is then avoided, and 10% POE and 50% POE outcomes are weighted 30.44% and 69.56% respectively.

Based on analysis leading up to this ESOO, AEMO has changed its approach, now using 30.44% weighting of 10% POE and 39.12% weighting of 50% POE outcomes (with a remaining 30.44% weighting attributed to a 90% POE that is assumed to lead to zero USE and therefore not modelled[79]).

A3.1 Background

The weightings have been derived using a mathematical approach. Expected USE was approximated using a Taylor series expansion. From three points – such as 10% POE, 50% POE and 90% POE – the weighting for these can be derived perfectly when:

- Maximum demand POE outcomes are normally distributed.
- USE outcomes as a function of maximum demand can be approximated by a second order (or lower) polynomial.

Additional points will allow a better fit for USE functions that are better approximated with higher order polynomials (of an order one lower than the number of maximum demand POEs used).

Using this mathematical approach, the three points – 10% POE, 50% POE, and 90% POE – have weightings of 30.44%, 39.12%, and 30.44% respectively. This forms the basis of the weightings used since 2002 at least[80].

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[79] Any simulations with USE above zero in the 90% POE case are likely to have so much USE in the 50% and 10% POE cases that it would be expected to be identified as exceeding the reliability standard, regardless of whether or not the 90% POE outcomes were modelled.

[80] See, for example, ROAM Consulting: "Critique of NEM Reliability Assessment Processes", report of National Generators Forum, 6 May 2004, available at https://www.aemc.gov.au/sites/default/files/content/001144dd-9e6c-4161-b40c-98735596f570/National-Generators-Forum-attachment-2.pdf.

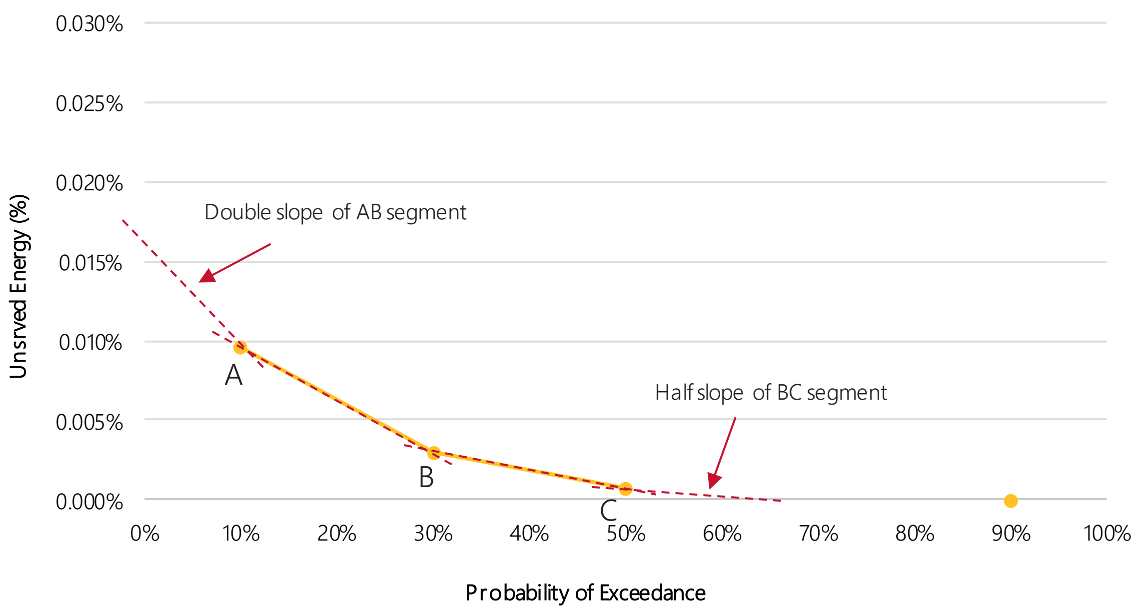
A3.2 Application of weightings

As maximum demand outcomes are not normally distributed (but somewhat close), and USE as function of maximum demand may not effectively be approximated by a second order (or lower) polynomial, AEMO has tested the performance of the approximation.

AEMO tested the use of these weightings (and others) against an USE outcome distribution estimated from simulating 10% POE, 30% POE, and 50% POE maximum demand profiles – and assuming any 90% POE simulations would result in zero USE.

Figure 47 below shows, using forecast Victorian USE for 2023-24 as an example, the estimated USE as a function of maximum demand POE when approximated from these three points. Values between these points were linearly interpolated and for POEs lower than 10%, USE outcomes based on doubling the slope seen between 10% and 30% POE were assumed. For POEs higher than 50%, USE outcomes based on halving the slope between 30% and 50% POE outcomes were assumed.

Figure 47 USE in Victoria in 2023-24, estimated as function of different maximum demand POEs



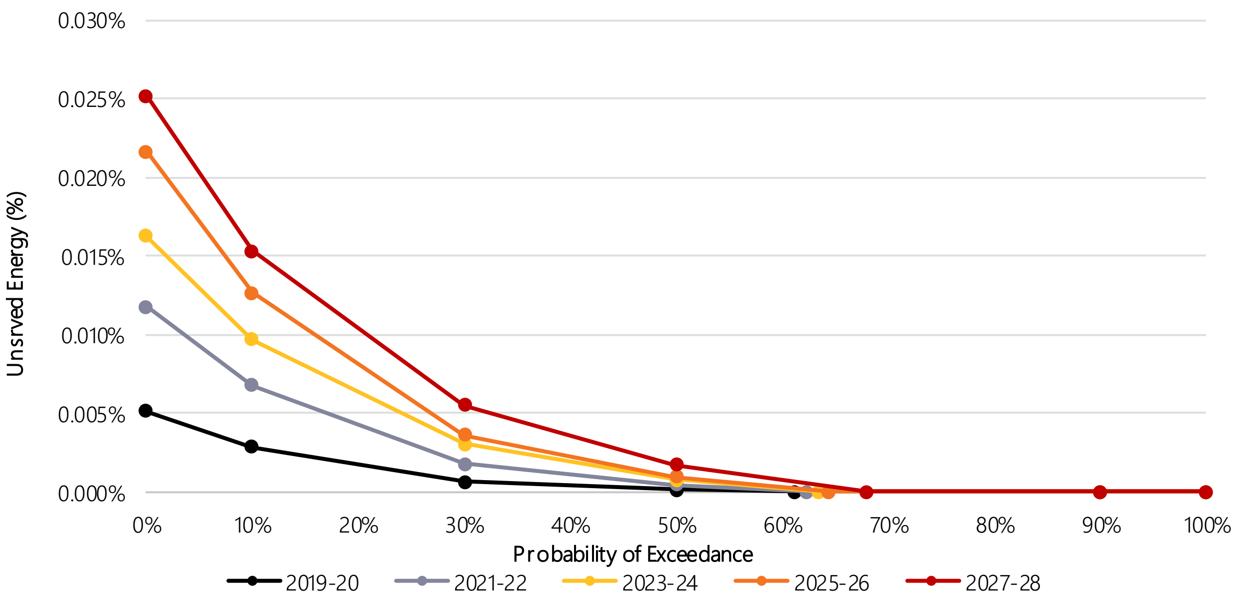
The empirical estimate of expected USE across that year was calculated as the area under the curve shown above. This was compared with expected USE calculated from weighting USE outcomes to validate or refute the weightings derived from the mathematical approach.

Table 22 Comparison of weighted estimates of expected USE against empirical estimate, Victoria, 2023-24

Method	Expected USE	Absolute difference
Empirical estimate (area under curve)	0.00299%	-
Weighting 10% POE outcomes 30.44%, 50% POE outcomes 39.12%	0.00323%	0.00024%
Weighting 10% POE outcomes 30.44%, 50% POE outcomes 69.56%	0.00346%	0.00047%

The analysis was undertaken for each region for a number of different forecast years, as demonstrated with Victoria in Figure 48.

Figure 48 Estimated USE in Victoria across different forecast years



The analysis showed:

- Applying 10% POE and 50% POE weightings of 30.44% and 39.12% (with the remaining 30.44% applied to 90% POE outcomes, which are assumed to be zero) provided a better fit with the empirically estimated USE outcomes explained above than the previously used 30.44% and 69.56% weightings.
- The weightings may result in a slight overestimation of USE (depending on what USE may actually result from maximum demand above 10% POE), although the overestimate is within the margin of error reasonably applied to the general forecast accuracy. This is due to the method assuming maximum demand POE outcomes are normally distributed, but the actual distributions are not quite normal. It should also be noted that the comparison was against an estimation, not actual USE (as only three points were known on the distribution).

Alternative options were considered, but were less consistent in performance across years and regions.

The benefit of continuing to use the mathematically derived weightings is that the same probability can be applied in every year and does not require calculation of more than two POE maximum demands.

A3.3 Applying weightings for Loss of Load Probability Outcomes

The assessment was also made using LOLP outcomes. The LOLP outcomes as a function of maximum demand are is generally more linear across POEs between 10% and 50%, but overall take the shape of an S-curve and can therefore both be convex and concave within that range, as shown in Figure 49.

The comparison of weighted and empirically estimated LOLP outcomes for Victoria for 2013-24 (same case as the USE example in Table 22) is shown in Table 23.

Figure 49 Loss of load probability in Victoria estimated as function of different maximum demand POEs

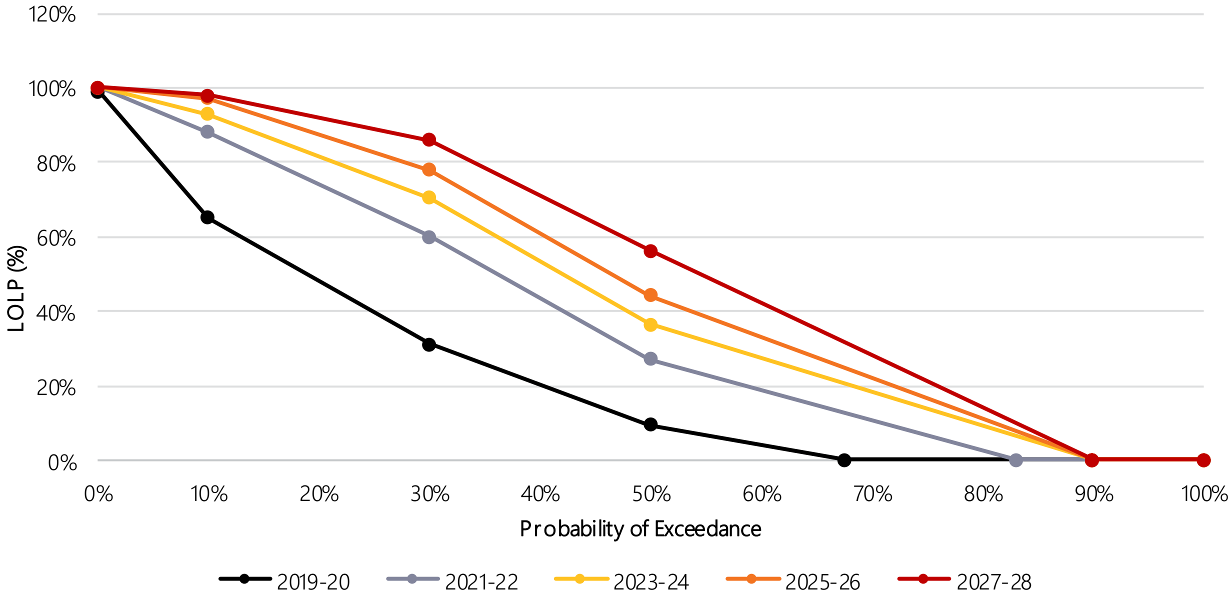


Table 23 Comparison of weighted estimates of LOLP against empirical estimate, Victoria, 2023-24

Method	LOLP	Absolute difference
Empirical estimate (area under curve)	43.92%	-
Weighting 10% POE outcomes 30.44%, 50% POE outcomes 39.12%	42.49%	-1.43%
Weighting 10% POE outcomes 30.44%, 50% POE outcomes 69.56%	53.55%	9.63%

Overall, across all regions and forecast years, the analysis still showed:

- For LOLP, the 30.44% and 39.12% weighting for 10% POE and 50% POE outcomes appears to be performing well and generally better than the 30.44% and 69.56% weightings.
- In some cases, these weightings are underestimating LOLP when assessed against the estimated LOLP outcomes, but generally LOLP is slightly overestimated.

There are no supply scarcity risks forecast in either Tasmania or Queensland over the 10-year modelling horizon.

Measures and abbreviations

Units of measure

Abbreviation	Full name
GW	Gigawatt
GWh	Gigawatt hour/s
kW	Kilowatt
kWh	Kilowatt hour/s
MW	Megawatt
MWh	Megawatt hour/s
TWh	Terawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
BoM	Bureau of Meteorology
CBD	CBD
CCGT	Closed-cycle gas turbine
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection
EEGO	Energy Efficiency in Government Operations

Abbreviation	Full name
EFI	Electricity Forecasting Insights
ESB	Energy Security Board
ESS	Electricity Storage System
ESOO	Electricity Statement of Opportunities
FRG	Forecasting Reference Group
GSP	Gross State Product
HDI	Household Disposable Income
HIA	Housing Industry Association
ISP	Integrated System Plan
LOLP	Loss of Load Probability
LRET	Large-scale Renewable Energy Target
MT PASA	Medium Term Projected Assessment of System Adequacy
MTTR	Mean time to repair
NABERS	National Australian Built Environment Rating System
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
QRET	Queensland Renewable Energy Target
RCP	Representative Concentration Pathway
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
STC	Small-scale Technology Certificate
USE	Unserved energy
VRET	Victorian Renewable Energy Target

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Criteria are outlines on each regional spreadsheet, under the Background information tab).
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
firming capability	Firming capability can be dispatched to maintain balance on the power grid. It can include generation on the grid, storage, demand resources behind the meter, flexible demand, or flexible network capability.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All the generating units in a region. • Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
maximum demand (MD)	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
mothballed	A generation unit that has been withdrawn from operation but may return to service at some point in the future.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational electrical consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.