AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

2019 Electricity Statement of Opportunities

August 2019

A report for the National Electricity Market

Important notice

PURPOSE

AEMO publishes the National Electricity Market Electricity Statement of Opportunities under clause 3.13.3A of the National Electricity Rules.

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VERSION CONTROL

Version	Release date	Changes
1	22/8/2019	Initial release
2	23/8/2019	Clarify some forecast numbers and dates with minor corrections: Executive summary, Sections 2.2.3, 3.1, A1.1, A1.1, A1.3, A1.4, and A1.5. Add commentary about short-term maximum demand: Sections A1.4 and A1.5. Correct footnotes: Executive summary, Sections 1.2 and 3.3. Add new footnote: Section A.1.1. Insert word to clarify actual LOR 2 or 3: Section 3.3.

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 decisions by market participants, investors, and policy-makers. From this year, the ESOO will include a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO)[1]. The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps.

The 2019 ESOO forecasts a continued elevated risk of expected unserved energy (USE)[2] over the next 10 years. Compared to last year's ESOO forecast, and based on improved model representation of input uncertainties, AEMO observes greater risks of load shedding due to uncontrollable, but increasingly likely, high impact ('tail risk') events such as coincident unplanned outages. The forecast reaffirms that targeted actions must be taken now to provide additional dispatchable capacity to reduce the risks of supply interruptions during peak summer periods.

Key findings

Summer 2019-20

- **AEMO forecasts** tightly balanced supply and demand in several NEM regions for summer 2019-20, with **all regions other than Victoria expected to meet the current reliability standard of expected USE not exceeding 0.002%.**
- **In Victoria, if extended into the peak summer period, the unplanned outages of two major power stations,** Loy Yang A2 (500 megawatts [MW]) and Mortlake 2 (259 MW), **pose a significant risk** of insufficient supply that could lead to material involuntary load shedding.
  - These units have announced a planned return to service in late December 2019. Based on historic experience with similar plant failures, and in light of the extended repairs that are required, AEMO's analysis assumes a 30% likelihood that the Loy Yang A unit outage will extend over the summer and a 60% probability that the Mortlake unit outage will extend into the summer months.
  - The assumed extended outages of either of these units, in combination with a number of other operating risks, including the continued deterioration of the reliability of aging brown coal units, result in **Victoria having an expected USE of 0.0026% for the coming summer**.
  - The **additional resource capability required in Victoria is projected to be between 125 MW and 560 MW**, to close the gap to the current reliability standard or reduce the likelihood of exceeding the standard to a 'one-in-10 year' event, respectively. However, if both power station outages were extended over the summer, and **if no additional supply was secured, involuntary load shedding may be experienced in Victoria during extreme weather events,** potentially over multiple events, equivalent to between 260,000 and 1.3 million households being without power for four hours.

[1] The RRO came into effect on 1 July 2019. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

[2] 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. 'Expected' refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

– AEMO is working with industry to secure the maximum permissible reserves via the Reliability and Emergency Reserve Trader (RERT) to ensure Victoria's reliability of supply meets the reliability standard this summer. AEMO is being supported to meet its responsibilities by the Victorian Government.

Forecasts beyond 2020

- **Beyond 2020, AEMO forecasts only slight improvements[3] in reliability for peak summer periods until new transmission and dispatchable supply and demand resources become available.** AEMO's 2019 ESOO reaffirms the message in the 2018 ESOO that additional investment will be required in a portfolio of resources ahead of time to replace retiring capacity.
- This ESOO analysis includes nearly five gigawatts (GW) of committed new generation projects and upgrades to existing generators expected to become available over the next three years, in addition to Snowy 2.0 (2,040 MW), which has been assumed to be fully operational by March 2025.
- Most of the announced new generation projects are variable renewable energy generators, which often do not generate at full capacity during peak demand times or may be positioned in a congested part of the network. As a result, while providing significant additional energy during many hours of the year, these projects are forecast to only make a limited contribution to meeting demand during peak hours
- The announced staggered closure of Torrens Island A Power Station will reduce available capacity in South Australia, causing a slow increase in expected USE to 0.0004% by 2021-22. The new proposed interconnector between South Australia and New South Wales is not modelled in this assessment, as it is not yet a committed project, but would reduce this risk by improving the sharing of resources across the NEM.

Impact of Liddell closure 2022-24

- AEMO forecasts that **the level of USE in New South Wales will increase following the gradual closure of Liddell Power Station, but remain slightly below the current reliability standard, reaching 0.00174% USE in 2023-24 after Liddell's full closure.** This analysis presumes no new investments in generation, transmission, or demand response, beyond what is already committed. It specifically does not include the benefits of the Queensland to New South Wales Interconnector (QNI) and the Victoria to New South Wales Interconnector (VNI) projects, because both projects are yet to receive full regulatory approval. Governments, the Energy Security Board (ESB), and the Australian Energy Regulator (AER) are working proactively on delivering both projects before the Liddell closure.
- The impact of the retirement of one unit at Liddell Power Station in April 2022 leads to an expected USE of 0.0002% in New South Wales in 2022-23. This USE level does not meet the "material reliability gap" threshold of 0.002%. **AEMO will therefore not request a T-3 reliability instrument under the newly introduced Retailer Reliability Obligation (RRO)**.
- However, as in Victoria this summer, following the gradual closure of Liddell, **a combination of high summer demand and unplanned generator outages will leave New South Wales exposed to significant supply gaps and involuntary load shedding if no mitigation action is taken**. In 2023-24, AEMO forecasts a risk to between 135,000 and 770,000 households in New South Wales being without power for three hours during an extreme heat event (that is, a 1-in-10 year peak demand event).
- The commissioning of Snowy 2.0 (assumed in this analysis to be fully operational by March 2025) will improve the reliability outlook, provided additional transmission necessary to serve load centres in Sydney and Melbourne is constructed. This transmission infrastructure has not yet received regulatory approval, so it is not included in this analysis. Work on these enabling transmission projects is being

[3] Relative to what the reliability outlook for this summer would have been had Loy Yang A Unit 2 and half of Mortlake Power Station not experienced electricity failures resulting in prolonged outages.

progressed by transmission network service providers (TNSPs), and will be further investigated in AEMO's 2019-20 *Integrated System Plan* (ISP).

Required actions

AEMO has identified a number of prudent and least-cost actions that should be taken to avoid consumer exposure to an unreasonable level of risk of involuntary load shedding during peak summer periods. Some of these actions are currently underway and should be pursued without unnecessary delay. Others will require changes to rules and/or additions to AEMO's authority. AEMO will seek to implement these recommendations through its continued work with the Commonwealth and State Governments, the ESB, the Australian Energy Market Commission (AEMC), and the AER.

1. **Summer readiness plan** – as it does every year, AEMO is already working proactively with industry and governments to prepare for the coming summer by implementing a comprehensive summer readiness plan to minimise risks as much as possible within the current rules framework. This year, AEMO is also working in depth with generators and industry experts to gain a better understanding of forced outage rates of aging generators to improve future reliability assessments, in particular in light of the increasing frequency of hard to predict but high impact events such as unplanned outages of dispatchable supply resources.
2. **Commissioning of targeted transmission augmentation** – the supply-demand balance in New South Wales will be significantly improved with the addition of the QNI and the New South Wales component of the VNI upgrades and, once completed, through HumeLink and EnergyConnect, as identified in the 2018 ISP. This ESOO reconfirms the importance of the work now underway to complete QNI and VNI ahead of the closure of Liddell Power Station, involving significant undertakings by governments, industry, the ESB, and the AER. To enhance the resilience of the NEM against the growth of systemic risks during the energy transition (for example, to enable the system to absorb the impact of deteriorating performance of aging plants), a new mechanism will be required for the fast-tracked delivery of 'no regrets' transmission infrastructure and transmission infrastructure that could deliver important reliability and resilience benefits. The 2019-20 ISP will identify essential 'no regret' and resilience projects, and AEMO will work with governments, industry, market bodies, and the ESB to develop a process by the end of 2019 to implement them.
3. **Dispatchable resources** – once the above transmission infrastructure is in place, AEMO's analysis projects that new dispatchable supply of approximately 215 MW would be required to ensure New South Wales only has a one-in-10 year risk of a significant involuntary load shed event in summer 2023-24, following the full closure of Liddell Power Station. Over the coming two months, AEMO will work with industry and governments to identify the attributes and location of dispatchable resources that will address this risk and available mechanisms to assure the necessary investment.
4. **Reliability standard** – the current reliability standard is based on the *expected* USE within a given financial year not exceeding 0.002%. Because applying this standard requires the averaging of annual USE over all possible outcomes, it effectively averages out the risk of experiencing the rapidly growing number of events which can cause severe load shedding over the summer period. While AEMO has attempted to 'operationalise' the risks within the existing standard as much as possible, a modified reliability framework that enables AEMO to ensure customers are not exposed to significant involuntary load shedding in nine out of 10 years is necessary. AEMO will accordingly pursue the development of a modified standard over the coming three months that can more cost-effectively and reliably provide the requisite level of dispatchable resources.
5. **Three-year strategic reserve** – in view of the current risk in Victoria, AEMO believes its inability to procure reserves over a three-year duration is imposing unnecessary risks and costs on Victorian consumers. AEMO will therefore continue look to obtain the necessary and prudent flexibility that maintains reliability at the lowest cost.
6. **Wholesale demand response** – AEMO is reviewing the recent decision of the AEMC to support the introduction of wholesale demand response in the NEM. As envisioned by the AEMC, AEMO will look for ways to accelerate participation by customers as a mechanism to support future reliability.

7. **Market reform** – the current forecast reliability risks, and the need for market-based investments, demonstrate the imperative to implement reforms in the NEM covering a number of areas. They include, for example, short-term forward markets, firming and security services markets, and markets to support investments at the right time and the right location, including nodal pricing and improved reliability mechanisms. AEMO will continue to work with the ESB and the other market bodies to help prioritise and progress market reforms that will improve how market participants can address consumer demands for reliable, secure, and affordable power.
8. **Notice and mechanism of closure** – the current three-year notice of closure rule for generators does not fully protect consumers from potentially significant high price and load shedding risks in the lead up to, and following, a major generator closure. As generators approach decommissioning, the risk of a major outage or unforeseen early exit due to economic consideration increases. Furthermore, the three-year closure period may not provide sufficient time to implement the most cost-effective replacement option, leading to higher cost outcomes for consumers. AEMO will work with governments, the ESB, and other market bodies to develop a proposal over the coming six months to refine the current rules to enhance long-term certainty of generator exit dates, while ensuring plant reliability in the lead up to the planned closure date.
9. **Information transparency** – AEMO is working with industry to increase the frequency and improve the content of information it publishes, to provide greater transparency and thereby improve decision-making. Improvements will include quarterly updates on generator commissioning and commitment in Generation Information Page updates[4]. AEMO will also investigate further generation, storage, demand side participation (DSP), and transmission measures in its upcoming 2019-20 ISP.

The Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) was introduced into the National Electricity Law (NEL) and National Electricity Rules (NER) with effect from 1 July 2019 when the *National Electricity (South Australia) (Retailer Reliability Obligation) Amendment Act 2019* (SA) came into force.

A key component of the RRO is the calculation of a five-year reliability forecast for each NEM region, published in this ESOO. An indicative reliability forecast is also produced for the remainder of the ESOO's 10-year outlook period. If the reliability forecast identifies a material reliability gap, that is, a reliability gap in excess of the reliability standard, AEMO must submit a reliability instrument request to the AER.

In recognition of the importance of the ESOO forecasts, AEMO has consulted extensively, facilitating multiple stakeholder workshops and reference group meetings to verify assumptions and approach for this year's ESOO. Forecasting approaches have also been improved, informed by ongoing monitoring of AEMO's forecast performance and market trends. The current reliability forecasts incorporate:

- 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.
- Improved understanding of the impact of existing and future energy efficiency measures on underlying demand.
- Updated data on the supply and DSP available to meet operational demand, including the latest information on generation in the NEM which is connected to, or is committed to connect to, the grid.
- New, station-specific information on the performance of existing conventional generation, that better reflects recent operating experience and year-on-year variations in performance across the fleet.
- Updated transmission constraints, in particular to reflect current voltage stability limits impacting imports to New South Wales from Queensland and Victoria.

[4] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

The RRO uses the current reliability standard as its trigger. The effectiveness of the RRO can be further improved by adopting an improved reliability standard as proposed in this ESOO, because the current reliability standard masks the level of dispatchable resources reasonably required to reduce the risk of significant involuntary load shedding events triggered by the effect of uncontrollable, but increasingly likely, high impact events such as coincident unplanned outages and high temperatures over peak summer periods

Until a new reliability standard is formally adopted, AEMO will continue to use the existing standard and forecasting methodology, which simulates thousands of different possible future supply and demand outcomes for each year of the reliability forecast to determine the distribution of annual USE. From this distribution, the expected USE is calculated to compare against the NEM reliability standard. The inputs, assumptions, and methodologies used in developing the reliability forecasts are published as supplementary material to this ESOO[5].

The ESOO analysis used to inform the core reliability forecasts considers the ability of only existing and committed generation and transmission to meet forecast demand. This provides an important input to AEMO's operational planning for summer readiness, because further market investment, above what is already committed, is unlikely to be available in the short term. Further, for RRO purposes, AEMO does not consider it appropriate to make assumptions around future reliability improvements until it is clear those improvements will be delivered.

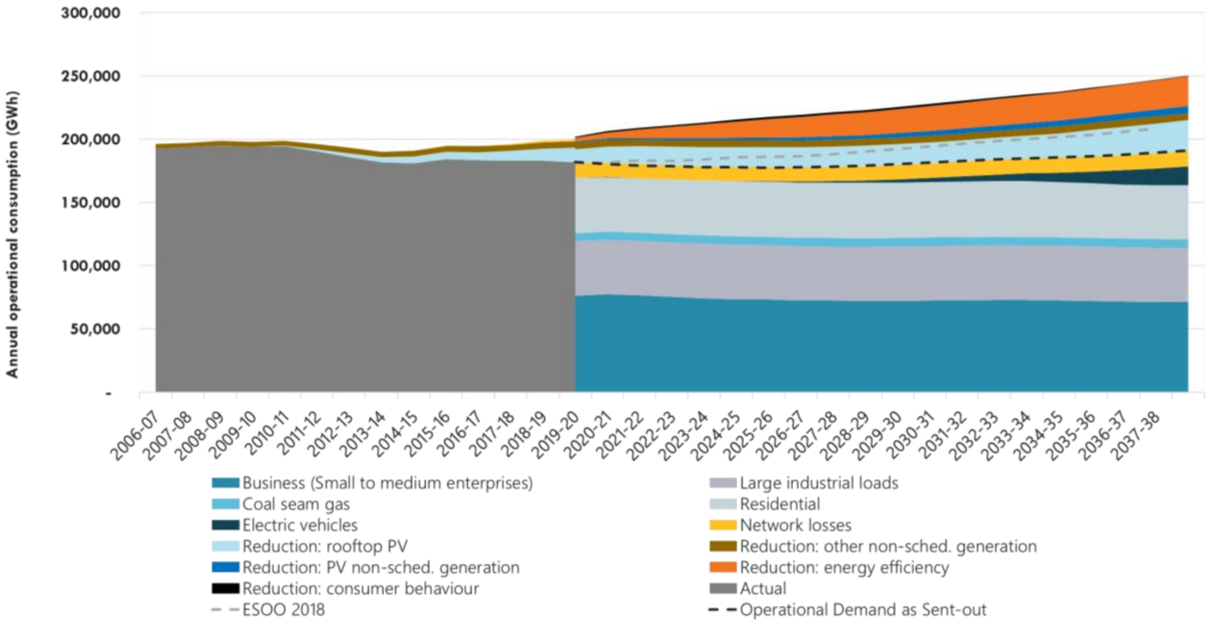
Investment is possible with sufficient lead time. New transmission developments, while not yet committed, are currently progressing through the regulatory process at an accelerated pace. In the medium to longer term, the ESOO highlights opportunities for market investment to meet consumer needs, with and without this new transmission development, and the risks if further investment in generation and DSP is not forthcoming.

Demand forecasts

Underlying and operational consumption forecasts

Figure 1 shows forecast underlying and operational consumption to 2038-39, and the factors that are expected to moderate operational consumption growth in that period.

Figure 1 Total NEM operational consumption in GWh, actual and forecast, 2006-07 to 2038-39



[5] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

Australia's population increase is expected to be the main driver of underlying consumption for the residential sector, and, along with mining activity, to be a key contributor to economic and consumption growth in the business sector. However, expected increases in energy productivity, continuing structural change in the economy away from energy-intensive industries, and increases in rooftop PV installations are expected to moderate further growth in both annual operational[6] consumption and maximum demand within the ESOO's 10-year outlook.

Compared to the 2018 ESOO, operational consumption forecasts under AEMO's Central scenario (formerly the 'Neutral' scenario) are now slightly lower (6% lower by 2028-29). This downward revision is due predominantly to greater expectations for energy efficiency contributions, and observed changes in the relationship between gross state product (GSP) and business consumption, driven by the changing structure of the economy.

Electrification of transport is still not projected to materially increase consumption until approximately 2028-29, when electric vehicle (EV) model choice, charging infrastructure availability, and cost reductions are projected to result in material increases in EV ownership.

In this ESOO, AEMO has also assessed two other scenarios:

- A Step Change scenario assumes higher economic activity, population growth, and greater electrification of the transport sector, as well as a step change in consumer-led investment in rooftop PV and energy efficiency measures. This leads to slightly lower forecast consumption of 174 terawatt hours (TWh) by 2028-29, compared with 179 TWh in the Central scenario.
- A Slow Change scenario assumes lower economic activity and population growth, reducing the forecast, although projected PV uptake is also slower. This scenario assumes some closures in at-risk energy-intensive sectors, leading to significantly lower consumption (168 TWh) than the Central scenario by 2028-29.

Maximum demand forecasts

In the last three years, load factors[7] have been decreasing, with record high maximum demand days still being observed despite operational consumption growth being in decline.

In Queensland, for example, average monthly maxima in the past 12 months are up 3% compared to a year ago, but annual energy is down 0.7%. Discussions with local network companies suggest a driver may be an increase in air-conditioner ownership coupled with consumers changing the way they use cooling, with less tolerance for high temperatures towards the end of summer.

Moreover, while rooftop PV uptake continues to have noticeable impacts on operational consumption, the forecast impact on operational maximum demand, which now occurs closer to sunset, is reduced.

In 2018-19, new record maximum operational demand was recorded for Queensland (summer operational maximum demand sent out of 9,512 MW) and South Australia (winter operational maximum demand sent out of 2,485 MW), with very high summer maximum demand outcomes also recorded in Victoria and South Australia. In 2018, Victoria saw its highest ever non-working day demand – on Sunday 28 January 2018 – at a time where distribution outages had more than 50,000 customers without power.

The 2018-19 summer was Australia's warmest on record, marked by persistent widespread heat, exceptional heatwaves, and below-average rainfall[8]. Despite record temperatures in many regions, all observed temperatures fell within the ranges expected by AEMO models, due to the included consideration of climate change in AEMO's forecasts.

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[6] See definitions at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

[7] Load factors are average consumption divided by maximum demand. Decreasing load factors indicate that the difference between average consumption and the peak is getting bigger.

[8] See Bureau of Meteorology, Australia in summer 2018-19, at http://www.bom.gov.au/climate/current/season/aus/archive/201902.summary.shtml.

Maximum demand over the next five years is forecast to:

- Remain relatively flat in New South Wales and South Australia, and to decline in Victoria, as growth in underlying residential and business load is offset by increasing energy efficiency.
- Continue growing in Queensland, due to growth in the business sector and large industrial loads.
- Grow in Tasmania in the initial years to 2021, driven by large industrial loads, and then to stay flat.

Minimum demand forecasts

Minimum demand forecasts are also important to understand, because low demand may cause system security risks. In all NEM regions:

- Minimum operational demand is forecast to continue declining over the next three to five years, due to forecast growth in rooftop PV and other small-scale PV capacity. In the past year, rooftop PV installations have grown by 20% in the residential sector and almost 35% in the business sector.
- Future growth in PV uptake is projected to be slower, due to a combination of declining incentives and easing of retail electricity prices. As a result, over the longer term, minimum demand forecasts remain relatively flat.

Given the growing importance of minimum demand, the 2020 ESOO will focus on this issue in more detail.

Supply availability forecasts

AEMO has undertaken a comprehensive stakeholder survey to capture commitments to construct utility-scale generation and storage in the next 10 years, based on AEMO's commitment criteria[9].

Approximately 4.9 GW of committed new renewable generation, storage, and thermal capacity[10] upgrades are expected to be available in the next few years, in addition to Snowy 2.0 (2 GW) which is assumed to be operational by March 2025.

A further 300 MW of projects are under construction and well advanced in satisfying the commitment criteria, but have not been assumed to be operational until after June 2021, regardless of targeted commercial use date, based on not yet reaching all the commitment criteria.

In some cases where technical information is outstanding or issues are unresolved, AEMO has been able to work with NSPs and proponents to facilitate early generation ahead of satisfying all commitment criteria. AEMO is aware of some risks with planned commissioning and recommissioning, and has undertaken sensitivity analysis to determine any impact of delays on summer reserves.

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.

Through consideration of operational experience, inputs from 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.
  - AEMO has also revised its application of generator forced outages so the modelling better represents the variation in forced outages observed in recent years.
  - Specifically, observed outage rates from the most recent four years have been discretely sampled for each power station, except where participants have provided compelling evidence to use an alternate

[9] The commitment criteria relate to site acquisition, contracts for major components, planning and other approvals, financing, and commissioning date. See the Background Information tab in each regional spreadsheet on AEMO's Generation Information web page, at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

[10] This includes scheduled and semi-scheduled generation – but excludes non-scheduled (<30 MW) installations.

forced outage rate going forward. Sampling of individual years has proven to give a better modelled approximation of aggregate availability across the fleet when compared to historical outages.

In 2019-20, AEMO will continue to assess performance of the aging fleet, including:

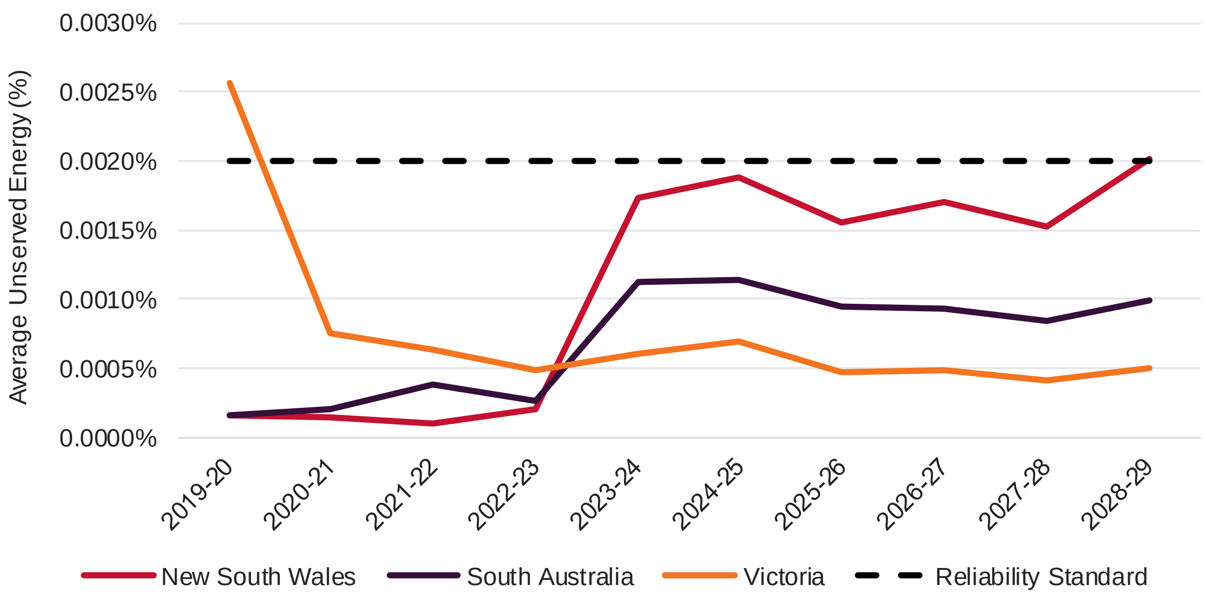
- Benchmarking reliability against international experience.
- Investigating the relationship between reliability and maintenance capital expenditure.

Reliability outlook

Based on the updated demand and supply forecasts, the 2019 ESOO presents forecast expected USE for all NEM regions. Figure 2 shows the forecast expected USE based on AEMO's Central scenario, and focuses on those regions where significant USE has been forecast.

This reliability outlook assesses the ability of only existing and committed generation to meet forecast demand, and does not assume any transmission augmentations or new transmission developments unless the regulatory investment tests for transmission (RIT-Ts) have been successfully completed.

Figure 2 Expected unserved energy, 2019-20 to 2028-29



Next year (2019-20)

The outlook for Victoria this summer is informed by advice from asset owners that both one Loy Yang A unit (500 MW) and one Mortlake unit (259 MW), currently being repaired, will be back in service in mid-December 2019. Both units are located in Victoria. Loy Yang A Unit 2 was damaged following an electricity short internal to the generator on 18 May 2019, while an electrical fault caused half of Mortlake gas-fired power station to shut down on 8 July 2019[11].

Due to the damage resulting from the failures, and the extensive repairs required, delayed return to service of one or both units is considered likely. Generators on such extended outages are often delayed in their return to service due to new, unforeseen issues with the plant that are revealed during repair and recommissioning, or to delays as parts need to be ordered, sourced, and shipped to Australia.

[11] See https://www.originenergy.com.au/about/investors-media/media-centre/statement_on_mortlake_power_station.html.

For 2019-20, the first year of the five-year reliability forecast, AEMO is 'operationalising' the assessment of expected reliability of supply in Victoria as best as possible within the current rules by taking into account estimated probabilities of delayed return to service.

Based on operational experience, AEMO's modelling assumed:

- A 30% probability that Loy Yang A Unit 2 remains out of service until 1 March 2020.
- A 60% probability that the Mortlake unit remains out of service until 1 March 2020.

Taking into account these probabilities of delay, the expected USE in Victoria this summer is 0.0026% of annual consumption, which exceeds the reliability standard. AEMO forecasts that approximately 125 MW of additional firm reserves would be required to meet the reliability standard this summer.

However, this level of reserves would be insufficient to adequately manage the potentially very severe negative outcomes that could occur in Victoria next summer – so-called 'tail risk' events:

- Assuming the above probabilities for a delayed return to service, AEMO's modelling projects an 18% probability (or roughly one-in-five chance) that neither unit will be available over the 2019-20 summer. In this case, expected USE would rise to 0.0047%.
- In the worst case of neither unit being available and Victoria also experiencing a one-in-10 year peak demand, USE could jump to unprecedented levels of 0.0148%. If the equivalent to approximately 125 MW of additional firm reserves was available, the expected USE in this case would reduce to 0.0038%, which would still be well above the reliability standard.
- If both generator outages extended over the summer and no additional supply was secured, involuntary load shedding may be experienced in Victoria during extreme weather events, equivalent to between 260,000 and 1.3 million households being without power for four hours.

Other NEM regions are projected to meet the reliability standard with a more comfortable margin this summer, although some risk of USE exists in South Australia and New South Wales. Delays to commissioning the current pipeline of renewable generation projects could further heighten supply scarcity risks across all NEM regions.

Mitigating risks this summer

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.

Given current weather conditions, and continuation of drought in some areas, bushfires may threaten the power system, limiting inter-regional transfer capabilities. The electricity demand forecasts for this summer already assume desalination plants need to run to top up water supplies for Victoria. These factors combined further increase supply scarcity risks. The potential impact of the ongoing 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.

AEMO is continuing to monitor and address risks of supply shortfalls in the lead up to summer 2019-20 as part of the NEM summer readiness program. Specifically, AEMO, with support from governments, will again work closely with industry to ensure that proactive maintenance has been carried out prior to summer, that resource capacity and availability issues are addressed, and that sufficient fuel is available for generation.

AEMO is also working with industry to secure the maximum permissible reserves via RERT to ensure Victoria's reliability of supply meets the reliability standard this summer. AEMO is being supported to meet its responsibilities by the Victorian Government. The RERT response may be sourced from a combination of additional supply capacity, energy storage, and demand response. The Victorian Government has also encouraged government organisations and industry partners to participate in the RERT. This 2019 ESOO reliability assessment, combined with RERT cost information, will help inform any decision on the volumes of RERT to acquire.

The temporary diesel generation in South Australia is not available to the market, and is therefore not included in this reliability assessment. It is, however, expected to be available for use as a last resort to avoid load shedding in South Australia, and may be offered for service in the RERT.

Early action from industry to help support Victorian electricity requirements has already been taken. AGL has advised[12], and it is assumed in this ESOO, that:

- Barker Inlet Power Station in South Australia will be commercially available from the beginning of December 2019.
- The planned mothballing of two units of Torrens Island A Power Station will be delayed from November 2019 until March 2020. AGL is currently seeking permission from the South Australian Government to continue to operate these units over this summer. As this permission has not been granted at the time of writing this report, the ESOO analysis does not assume these units are able to be operated.

Operation of these two units over summer would improve the reliability outlook for Victoria, reducing expected USE to 0.0020%, provided there is sufficient interconnector capacity available to import supply from South Australia. While this would just meet the reliability standard, large supply scarcity risks remain if either the Mortlake or Loy Yang A2 outages are extended, or extreme weather conditions prevail.

Short-term reliability outlook: 2-5 years ahead

This ESOO modelling incorporates the announced retirements of the Torrens Island A Power Station in South Australia (480 MW, between 2020 and 2021), Liddell Power Station in New South Wales (450 MW in April 2022 and 1,350 MW in April 2023), and Osborne Power Station in South Australia (172 MW in 2023-24).

For the remainder of the five-year reliability forecast period, the 2019 ESOO projects:

- Following the announced staggered closure of one unit of Liddell Power Station in 2022-23, New South Wales' forecast expected USE does not meet the RRO threshold, so AEMO will not be submitting a request to the AER for a T-3 reliability instrument.
- During 2022-23, expected USE is 0.0002% in New South Wales and rises to 0.0017% in 2023-24, almost exceeding the current reliability standard. The outlook for New South Wales, however, contains the risk of potentially significant load shedding events that are discussed more fully in the next section.
- The new renewable generation coming online makes only a small improvement to the reliability outlook. Victoria, in particular, remains vulnerable to uncontrollable, high impact events such as prolonged or coincident generator outages, as experienced last summer and again in winter 2019.
- South Australia sees expected USE increase slightly from 2020-21 as the two remaining units of Torrens A are mothballed, followed by a steep increase in USE to 0.0011% in 2023-24 after Osborne Power Station's announced decommissioning[13].

Medium-term opportunities: 6-10 years ahead

For the remainder of the 10-year ESOO horizon, the indicative reliability forecast shows:

- Expected USE in New South Wales remains high and hovers around the reliability standard. The committed Snowy 2.0 pumped storage (assumed fully operational by end of March 2025) leads to no significant improvement in reliability, because transmission remains a limiting factor in transferring supply to the region's load centres. This can be helped by the HumeLink proposal being progressed by TransGrid in its current RIT-T[14].

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[12] See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa.

[13] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[14] See https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network.

- In the final year, 2028-29, expected USE in New South Wales rises again, driven by forecasts of increasing demand, mainly due to projections of growth in EV uptake starting to become significant from that year.
- Forecast expected USE continues to reduce slowly in Victoria as more renewable generation is commissioned to meet the Victorian Renewable Energy Target (VRET), although this analysis does not assume any further deterioration in brown coal generation reliability beyond what has been recently observed.
- Driven by growth in forecast demand, Queensland is projected to start seeing some risks of USE, although well below the levels forecast for other mainland regions.
- Tasmania has no forecast USE across the entire modelling horizon.

Other risks

- Gas supply gaps – the 2019 *Gas Statement of Opportunities* (GSOO) identified potential gas supply gaps in southern Australia from 2024 unless additional southern reserves and resources, or alternative infrastructure, are developed. USE on high demand days may be exacerbated by these potential gas supply shortfalls if no new gas projects are committed, although, depending on pipeline deliverability, the Gas Supply Guarantee may lessen the impact on the electricity sector.
- Power station retirements – the retirement of any full power station on the mainland would require significant investments, several years ahead of the event, to ensure the reliability standard is met. Transparency and certainty about closure dates from aging thermal plant fleet is extremely important to manage these closures without causing significant risks of USE and ensure cost-effective, long-term solutions can be implemented ahead of time.

The case for modifying the reliability standard

Several trends are combining to significantly increase the risk of actual USE exceeding 0.002% in a given year:

- The NEM has experienced significant tightening in its supply-demand balance in recent years following the retirement of thermal generation.
- The trend of increasing maximum temperatures not only leads to higher demand, but also lowers supply due to derating of generation and transmission.
- Peak demand growth is further exacerbated by changing consumer behaviours.
- At the same time, the growing amount of renewable generation increases the variability in the system. This increases reliance on the remaining thermal generation fleet, which consists of aging assets that have an increased risk of forced outages, as observed in Victoria on 24 and 25 January 2019 and again in winter this year.

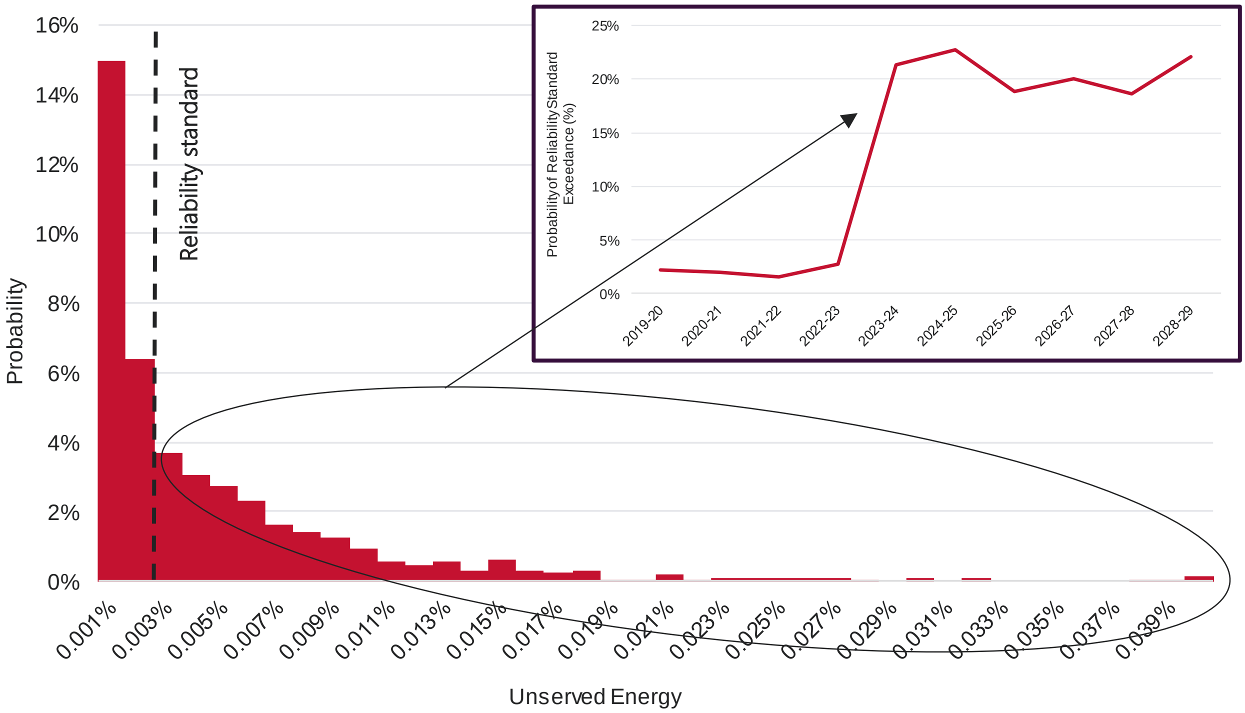
The forecast for New South Wales in 2023-24 is an instructive example, illustrated in Figure 3 (the figure excludes the cases with no USE, to allow focus on the tail risk).

AEMO's modelling indicates that, for New South Wales in 2023-24:

- While 'expected' USE is 0.00174%, which is within the current standard, there is a significant risk that actual USE may be significantly higher than 0.002%. In fact, analysis indicates a 21% probability that USE will exceed 0.002% in 2023-24.
- Depending on the coincidence of unplanned outages and extreme weather events, load shedding could be experienced during an extreme one-in-10 year heat event, equivalent to between 135,000 and 770,000 households in New South Wales being without power for three hours, potentially over multiple events.

The reliability standard is fundamental to AEMO's reporting obligations and capacity to utilise emergency reserve (RERT) powers.

Figure 3 Distribution of annual unserved energy in New South Wales, 2023-24



Because of the way the standard itself is framed[15], it does not capture the potential full impact of these uncertainties and associated risks. Uncontrollable, but increasingly likely, high impact ('tail risk') events, such as coincident unplanned outages, are masked in the current reliability standard, which requires USE to be *averaged* across the full range of possible outcomes for a *given financial year*.

In its March 2018 Final Determination on AEMO'S rule change Proposal for an Enhanced Reliability and Reserve Trader submission, the AEMC agreed with AEMO that the 'tail risk' poses a potentially significant risk to consumers, and recommended that AEMO 'operationalise' the reliability standard to account for changes to the power system.

In the preparation of this year's ESOO, AEMO sought to 'operationalise' the reliability standard to address the tail risk exposure to involuntary load shedding. For a number of reasons, described below, the NER does not provide AEMO with sufficient ability to fully address the tail risk:

- First, AEMO considered whether it can change the probability weights for extreme events or the period it considers for the calculation of USE.
  - The reliability standard is clearly defined in clause 3.9.3C(a) of the NER as "a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year". AEMO cannot change or deviate from this standard simply by changing its forecasting guidelines.
  - AEMO calculates the *expected* value of possible USE outcomes, in accordance with this well-defined mathematical concept[16]. To calculate an expected value, the probability weights for potential outcomes have to be chosen such that they are representative of the likelihood of each particular outcome occurring. AEMO has to use reasonable and defendable weightings for potential negative outcomes (for example, possible delays in the return to service of generators), and therefore has limited discretion in selecting probability weights.

[15] The reliability standard is defined in clause 3.9.3C(a) of the NER as the "a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year."

[16] See the Reliability Panel's Reliability Standard and Settings Review 2018 at p.52, and the Reliability Panel's Reliability Standard and Reliability Settings Review 2014 at p.23: https://www.aemc.gov.au/sites/default/files/2018-04/Reliability%20Panel%20Final%20Report.pdf.

- Furthermore, the standard requires AEMO to calculate USE outcomes over a whole year, rather than just the critical summer period.

- Second, AEMO considered progressively adjusting its probability weightings for high impact events over time as new information becomes available. AEMO could then re-calculate USE and utilise the mechanisms at its disposal to manage such events.
  - While the certainty of a high impact event occurring may increase over time (but does not necessarily), by the time the certainty is sufficient to act with the current tools, the time to respond may have passed. For example, AEMO might have a very high degree of certainty in early December this year that a generator outage in Victoria will extend over the summer. However, this knowledge would be of very limited practical value, because there would be insufficient time to physically procure, install, and connect the necessary emergency reserves.
- Third, AEMO considered using a non-normal distribution of demand outcomes, which would allow it to increase the weighting of one-in-10 year peak demand events in its USE assessment.
  - AEMO is currently assuming a normal distribution of demand outcomes, which is a well-established concept in mathematical statistics that represents the actual demand distribution well. Based on data from a research project AEMO is currently conducting with the Bureau of Meteorology (BoM), AEMO has estimated actual distributions of peak demand and compared them with its current approach. The resulting difference in USE outcomes was less than 10%, and therefore does not make a material difference to its assessment.
  - By the time there may be greater certainty that a particular region is likely to experience a one-in-10 year peak demand, there will again be insufficient time to meaningfully prepare for this outcome.

For these reasons, AEMO is unable to 'operationalise' the standard in a way that mitigates the potentially severe USE outcomes under the current rules. Given the increasing amount of tail risk, with its potentially severe economic and social effects, AEMO will pursue a submission to refine the reliability standard to ensure:

'***there are sufficient dispatchable reserves (MW) available in each region such that USE is less than 0.002% of total energy demanded in 9 out of 10 years***.'

This approach draws on much of the same analysis as AEMO currently uses to calculate the expected USE under the current reliability standard. The key difference is that it focuses on the *likelihood* of USE being less than 0.002% of total energy demanded, instead of the *expected* USE being less than 0.002% of total energy demanded. AEMO will work with the Commonwealth and State Governments, the ESB, and the AEMC to explore the implementation of this refined standard operationally.

When improving reliability in this way, great care needs to be taken to minimise the associated cost to consumers, and to allocate this cost in an equitable fashion. Additional reserves could come from demand response, energy storage, improved interconnection, dispatchable generation, or other resources. The actual cost of the additional reserves required would depend on the way it would be implemented.

With a well-designed, predictable market mechanism that captures the full range of low-cost or value-adding opportunities for response (for example, demand response, virtual power plants, batteries, and strategic interconnectors), AEMO believes long-term costs could be lower than the Value of Customer Reliability (VCR)[17]. Focusing the mechanism on demand response would also maximise consumer choice – consumers who prefer lower prices over higher reliability can achieve this by providing demand response services, and consumers who expect a higher level of reliability can enjoy the full benefits of the higher standard.

[17] The VCR represents a customer's willingness to pay for the reliable supply of electricity. For information, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

Forecast reliability gaps

For regions where forecast reliability gaps are close to, or exceed, the current reliability standard, Table 1 provides the megawatts projected to be required to achieve both the current reliability standard and the refined standard proposed above. Note that this table does not include the generation and transmission projects discussed below.

Table 1 Reliability gap (in MW) based on reliability standard and refined standard

	Gap to meet existing reliability standard			Gap to meet proposed refined standard		
	Victoria	South Australia	New South Wales	Victoria	South Australia	New South Wales
2019-20	125	0	0	560	0	0
2020-21	0	0	0	35	0	0
2021-22	0	0	0	0	0	0
2022-23	0	0	0	0	0	0
2023-24	0	0	0	0	135	375
2024-25	0	0	0	0	150	375
2025-26	0	0	0	0	95	300
2026-27	0	0	0	0	100	345
2027-28	0	0	0	0	70	300
2028-29	0	0	5	0	105	480

Pipeline of projects to help meet the reliability gap

The significant pipeline of projects across all NEM regions – including generation, storage, DSP, and transmission projects – can address the risks of USE.

Generation and storage

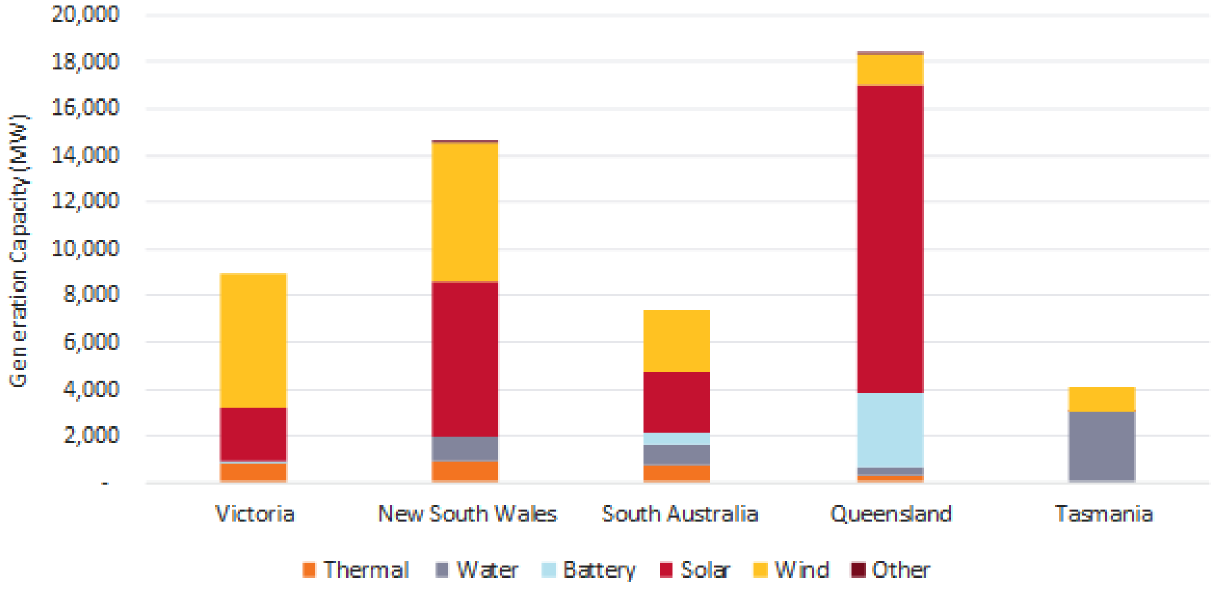
There is a substantial pipeline of generation and storage projects, from publicly announced to advanced stages of planning. If enough of these are committed and commissioned in time, it will help mitigate risks of USE exceeding the reliability standard and the impacts of tail risks.

Figure 4 shows the pipeline of projects by region, beyond already committed projects.

The impact of these added resources on reliability outcomes depends on the type. Dispatchable[18] generation types, such as storage or thermal generation, have the biggest impact. For variable renewable generation resources, a smaller amount of installed capacity can be counted on to be dispatchable when most needed.

[18] 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, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

Figure 4 Proposed projects by NEM region, beyond those already committed



For DER, DSP, and virtual power plants, AEMO is:

- Developing an integrated DER strategy considering operational processes, standards, market frameworks, data visibility, and network incentives to more effectively manage market conditions.
- Working in partnership with Energy Networks Australia on the Open Energy Networks project, to recommend a regulatory framework which will enable DER to be aggregated, incentivised, and optimised in the distribution network to allow greater uptake of consumer-owned battery and solar systems.

By 2029, based on the levels of behind-the-meter battery installations and default levels of aggregation assumed in this ESOO analysis, market mechanisms to facilitate greater levels of DER coordination could provide up to 580 MW of additional supply at times of high demand across regions. The AEMC is also working on finalising a rule change intended to promote additional DSP in the wholesale market[19].

Transmission

AEMO has proposed a number of transmission augmentations and new developments in its 2018 ISP[20] and recent ISP Insights Paper[21] to address bottlenecks within NEM regions or the flowpaths between them.

In this ESOO, AEMO has assessed the impacts on expected USE from the following 2018 ISP Group 1 projects:

- VNI minor upgrade – modelled as fully operational in September 2022.
- QNI minor upgrade – modelled as fully operational in September 2022.

Commissioning some of these projects by these dates, ahead of the Liddell Power Station closure, is projected to reduce risk of exceedance of the reliability standard in New South Wales.

Without the transmission augmentations, 375 MW of additional reserves is projected to be required in New South Wales to reduce the risk of a major load shedding event to a one-in-10 year event.

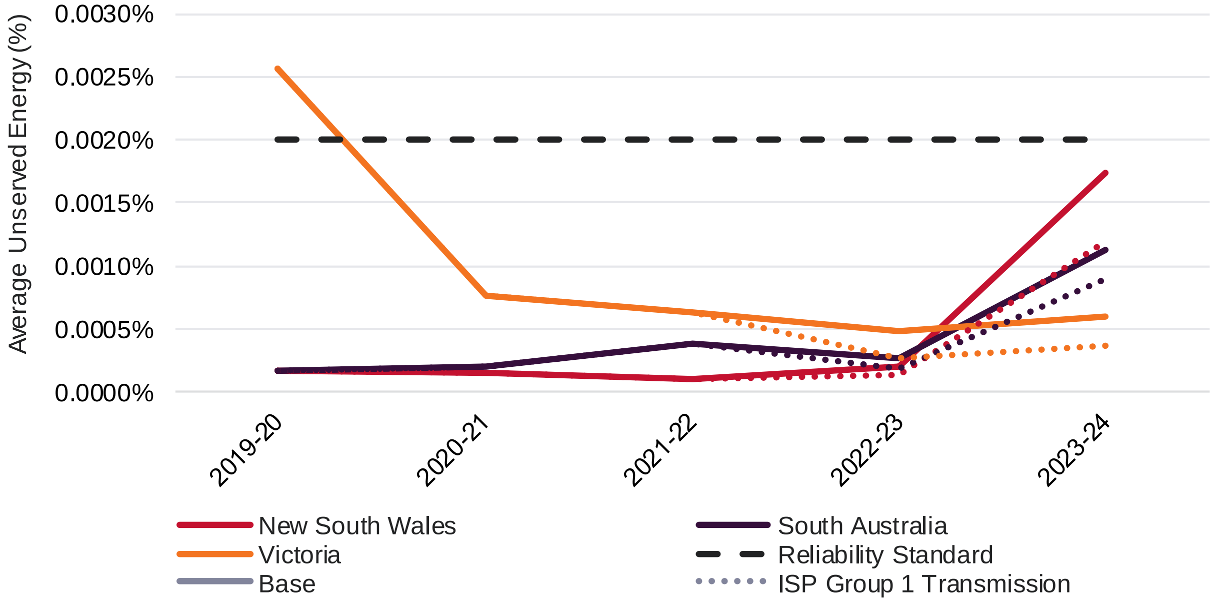
Once the QNI and New South Wales components of VNI are fully committed to be delivered by the target date, this figure would reduce to 215 MW, and expected USE in the region is projected to reduce from 0.0017% to 0.0012%, as shown in Figure 5.

[19] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

[20] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[21] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Insights---Building-power-system-resilience-with-pumped-hydro-energy-storage.pdf.

Figure 5 Impact on USE from delivering ISP Group 1 projects



To ensure these projects are fully tested and commissioned by the time they are needed, they are being targeted for completion by September 2021. This timeline will allow for the network capacity to be released and outages to be planned, with a buffer for unexpected delays in construction or approval.

TNSPs require the regulatory processes to be completed before they commit to these projects. TNSPs, and the relevant authorities, are therefore progressing these projects as a matter of priority.

Contents

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Figures

1. Introduction

1.1 Purpose and scope

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period to inform decisions by market participants, investors, and policy-makers. It includes information on:

- Existing, committed, and proposed electricity supply and network capabilities.
- Planned generating plant retirements.
- Operational consumption and maximum demand forecasts.
- Potential unserved energy (USE) in excess of the reliability standard that has been identified over a 10-year outlook period under a range of demand and supply scenarios.

For the purposes of the National Electricity Rules (NER) clause 3.13.3A(a), the following information should be considered part of the 2019 ESOO:

- The 2019 ESOO report and supplementary information published on the 2019 ESOO webpage[22].
- The 8 August 2019 Generation Information page update[23].
- The 2019 Inputs and Assumptions workbook[24].

From this year and onwards, the ESOO will include:

- **Reliability forecasts** identifying any potential reliability gaps for each of this financial year and the following four years, as defined according to the Retailer Reliability Obligation (RRO)[25].
- An **indicative reliability forecast** of any potential reliability gaps for each of the final five years of the 10-year ESOO supply adequacy forecast.

Reliability forecast under the Retailer Reliability Obligation (RRO)

In the 2019 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute Chapter 6 in this report.

Operational consumption and maximum demand forecasts are provided over a 20-year period from 2019-20 to 2038-39, because these forecasts are used by stakeholders for a range of purposes, including longer-term planning studies.

[22] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[23] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[24] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[25] The RRO came into effect on 1 July 2019 through changes to the National Electricity Law, the National Electricity Rules, and South Australian regulations. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

1.2 Key definitions

Reliability forecast components

Unserved energy (USE) is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer 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[26] should not exceed 0.002% of total energy consumption in any region in any financial year.

Reliability forecast under the Retailer Reliability Obligation (RRO)

For the RRO, components of any reliability forecast or indicative reliability forecast must include the USE, and whether or not there is a **forecast reliability gap**. Such a gap exists for a NEM region, and is considered material, if the forecast expected USE exceeds the reliability standard. If there is a forecast reliability gap, the reliability forecast must also include:

- The forecast reliability gap period (start and end date), and trading intervals in which forecast USE is likely to occur.
- The expected USE for that forecast reliability gap period.
- The **size of the forecast reliability gap** (expressed in megawatts).

AEMO's calculation of the size of the forecast reliability gap represents the additional quantity of dispatchable[27] capacity or equivalent that AEMO forecasts will be needed in the region within the forecast reliability gap period to maintain reliability within the reliability standard.

The RRO also introduces numerous other concepts related to the reliability forecasts published in this 2019 ESOO. These include:

- **T-3 cut-off date** – three years before the start of any forecast reliability gap.
- **T-3 reliability instrument** – if a reliability forecast identifies a reliability gap in a region up to six months ahead of the T-3 cut-off date, AEMO must make a request to the Australian Energy Regulator (AER), no later than three months prior to the T-3 cut-off date, for a T-3 reliability instrument to be issued. In relation to the 2019 ESOO reliability forecast, this could relate to a forecast reliability gap in the financial year 2022-23.
- **T-1 cut-off date** – one year before the start of any forecast reliability gap.
- **T-1 reliability instrument** – if a T-3 reliability instrument exists for a period and a reliability forecast in the second financial year following that instrument identifies that the forecast reliability gap remains, AEMO must make a request to the AER for a T-1 reliability instrument to be issued. This request must be made no later than three months prior to the T-1 cut-off date.

If the AER chooses to make both T-3 and T-1 reliability instruments in response to those AEMO requests, a number of compliance obligations for liable entities under the RRO may be triggered.

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26 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 3.9.3C(b)(2)). 'Expected' in this ESOO refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

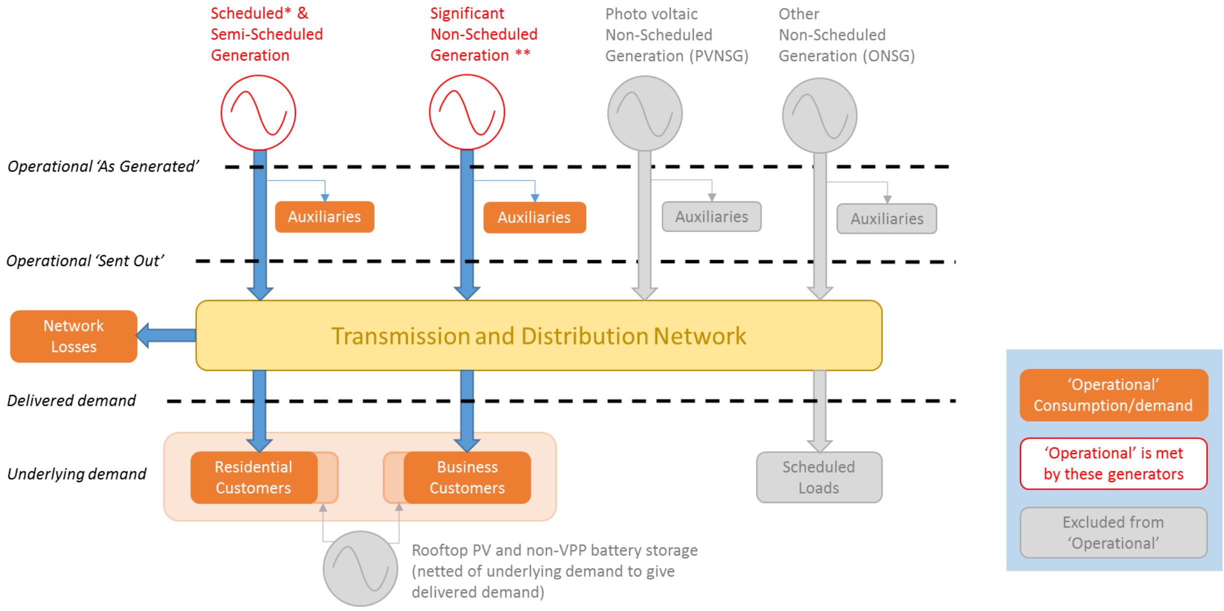
27 The dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target', and incorporates how controllable the resources are, how much they can be relied upon, and how flexible they are. For more information, see AEMO's *Power System Technical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

Under the South Australian application legislation[28], the Minister will also have powers to make a T-3 reliability instrument for that region (in the transitional period, this may be only 15 months in advance).

Demand forecasts

Consumption and demand can be measured at different places in the network. The forecasts in this report refer to **operational consumption/demand (sent out)**[29] unless otherwise stated. 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). Demand definitions are shown in Figure 6.

Figure 6 Demand definitions used in this report



* Including VPP from aggregated behind-the-meter battery storage
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pd .

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, plus 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.

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) and **as generated** (including 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 (and also called one-in-10).

[28] See: *National Electricity Law (South Australia) 1996* (SA) Part 7A.

[29] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

NEM time – the NEM is operated on Australian Eastern Standard Time, which does not include daylight savings. Time is reported on that basis unless otherwise noted.

1.3 Forecasting reliability

The 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.

Overall approach to calculating USE

To forecast reliability of supply for the NEM in the 2019 ESOO, AEMO has:

- Developed new demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in behaviour by household and business consumers. The forecasts for operational or delivered consumption include forecasts for advances in energy efficiency (EE) and growth in distributed solar generation and battery storage systems.
- Updated the supply available to meet this demand to include the latest information on generation in the NEM or which is committed to connect to the grid.
- Reviewed the performance of existing conventional generation based on historical performance data, and refined the modelling of its reliability to better reflect recent operating experience and future uncertainties. Some allowance has also been made to reflect the performance of the major interconnectors, reflecting their importance in delivering reliable supply to customers.
- Modelled using a statistical simulation approach[30], which assesses the ability of existing and committed[31] generation to meet forecast demand in all hours. The model calculates an average USE over a number of demand and renewable generation outcomes (based on nine 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 forecast USE.

Pain sharing is not included in the 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.

USE and investment needs

The expected USE calculated through the statistical model is compared against the maximum threshold specified by the NEM reliability standard. If the threshold is exceeded, AEMO calculates the reliability gap size, indicating the need (in megawatts) for dispatchable generation or equivalent required to reduce USE so the standard will be met.

Further investment is possible with sufficient lead time, provided a conducive investment landscape exists. In the medium to longer term, the ESOO highlights the opportunities for market investment to meet customer needs, and the risks if investment is not forthcoming.

From 2019, the ESOO also serves to highlight any T-3 reliability gaps that could trigger AEMO to submit a reliability instrument request to the AER under the RRO[32]. This process is designed to incentivise and facilitate

[30] See ESOO Methodology Report, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[31] Commitment criteria are listed and explained under the Background Information tab in each regional spreadsheet on AEMO's Generation Information web page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[32] A T-1 reliability gap cannot be called this year, because an existing T-3 request must have been declared for that particular region first.

adequate investment in supply and demand side participation (DSP) from dispatchable resources (including DSP) to close the gap within the next three years.

A range of trends is combining to create a significantly increased risk of actual USE exceeding 0.002% in any given year:

- The NEM has experienced significant tightening in its supply-demand balance in recent years following the retirement of thermal generation.
- At the same time, the large amount of renewable uptake increases the variability in the system. This increases reliance on the remaining thermal generation fleet with aging assets that have an increased risk of forced outages, as observed in Victoria in January 2019 and again in winter 2019.
- Changing consumer behaviours around cooling preferences, combined with increasing maximum temperatures in summer, put upward pressure on demand on very hot days.
- Increasing maximum temperatures may also lead to reduced supply, due to derating of generation and transmission.

Compared to last year's ESOO forecast, based on improved model representation of these input uncertainties, AEMO observes greater risks of load shedding due to uncontrollable, but increasingly likely, high impact ('tail risk') events such as coincident unplanned outages.

This heightened level of risk is not captured by the existing reliability standard, which focuses on average forecast USE only. As a result, in this ESOO AEMO suggests a refinement to the reliability standard to reduce the risk of significant USE caused by high impact events. This approach would require changes to the Rules and/or Guidelines.

Within an operational timeframe, AEMO will continue to 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, if a supply shortfall is projected in the coming summer. The ESOO analysis is therefore an important input to AEMO's operational planning, because further market investment – above what is already committed – is unlikely to be available in the short term.

1.4 Scenarios

The reliability forecasts presented in the ESOO are impacted by two key factors in the 10-year outlook:

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

The 2019 ESOO focuses on AEMO's Central scenario, and provides reliability outcomes for two alternative futures[33], as outlined in Table 2.

These three scenarios are a subset of the five developed in consultation with industry and consumer groups for use in AEMO's 2019-20 forecasting and planning publications, including the *Integrated System Plan* (ISP).

For each of the alternative scenarios, the NEM's available supply reflects only the existing and committed generation (as discussed in Chapter 4). The reliability forecasts therefore identify whether there is sufficient available and committed capacity to meet the reliability standard under each scenario.

[33] More information is available in AEMO's 2019 Forecasting and Planning Scenarios, Inputs, and Assumptions report, at https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

AEMO has also undertaken an additional sensitivity study, exploring the projected reliability impacts of two of **the 2018 ISP group 1 projects being implemented**: a Queensland to New South Wales Interconnector (QNI) upgrade[34], and a Victoria to New South Wales Interconnector (VNI) upgrade[35].

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this ESOO

Driver	Slow Change scenario	Central scenario	Step Change scenario
Demand drivers			
Economic growth and population outlook	Low	Moderate	High
Energy efficiency improvements	Low	Moderate	High
DSP	Low	Moderate	High
Representative Concentration Pathway (RCP) (average temperature rise by 2100)*	RCP 8.5 (>4.5°C)	RCP 7.0 (3.0 – 4.5°C)	RCP 1.9/2.6 (1.4 – 1.8°C)
DER uptake			
Rooftop PV – up to 100 kW – and non-scheduled PV – from 100 kW to 30 MW	Low	Moderate	High
Battery storage installed capacity	Low	Moderate	High
Battery storage aggregation/virtual power plant (VPP) deployment by 2050	Existing trials do not successfully demonstrate a strong business case for VPP aggregation. Low role for energy storage aggregators and VPPs.	Moderate role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs, faster than all other scenarios.
Electric vehicle (EV) uptake			
EV uptake	Low	Moderate	High
EV charging times	Delayed adoption of infrastructure and tariffs to enable 'better' charging options.	Moderate adoption of infrastructure and tariffs to enable 'better' charging options.	Faster adoption of infrastructure and tariffs to enable 'better' charging options.

* For more information on Representative Concentration Pathways (2.6, 4.5, 6.0, 8.5) see https://www.climatechangeinaustralia.gov.au/en/publications-library/technical-report/. Additional RCPs (1.9, 3.4, 7.0) are emerging through work by the Intergovernmental Panel on Climate Change (IPCC) sixth assessment due to be published in 2020-21, and are developed on a comparable basis.

The selected scenario narratives are:

- **The *Central scenario*** reflects the **current transition of the energy industry** under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current Commonwealth and State Government policies. This scenario assumes a range of best estimate projections of economic growth, population growth, and

[34] Interconnector upgrade currently being progressed by Powerlink and Transgrid. See https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity.

[35] Interconnector upgrade currently being progressed by Transgrid and AEMO. See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

electric vehicle (EV) uptake. Existing market settings, tariffs and policies drive energy efficiency activities and DER uptake. Existing trials lead moderate growth in aggregated virtual power plants (VPPs) to offset the need for additional supply, while household batteries operate to maximise the individual household's benefit.

- **The *Slow Change*** scenario reflects a **general slow-down of the energy transition**. It is driven by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial and consumer motivation to make the upfront investments required for significant emissions reduction. The slower population growth outlook lowers broader economic growth and limits household disposable income growth. Weak economic conditions lead to higher risk of industrial demand closures, while business and residential loads seek to lower consumption to manage bill exposure. With less disposable income and fewer policy settings to support DER, investment in rooftop PV, batteries, and EVs is reduced relative to the Central scenario. Australia does not actively promote local EV deployment.
- **The *Step Change*** scenario reflects **strong action on climate change** that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster **technological improvements**, accelerated exit of existing generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and **consumer-led innovation**. Higher economic and population growth and greater innovation in digital trends leads to stronger investment in EE, DER, and EVs. Existing VPP trials demonstrate a strong role for VPPs, reducing the need for large-scale supply, while tariff reform enables greater adoption of smarter charging behaviours by customers with batteries and EVs to offset household demand.

1.5 Improvements for 2019 ESOO

The NEM is facing increasing uncertainty, driven by an aging generation fleet, forecast rapid uptake of new technologies (such as rooftop PV and battery storage), industry restructuring, and consumer engagement enabled by new offerings and tariff signals. AEMO has made a number of improvements to its 2019 ESOO, to ensure it captures these changes adequately.

The accuracy of AEMO's forecasts is assessed at least annually through the Forecasting Accuracy Reports[36], which assess the accuracy of consumption, maximum demand, minimum demand, and key input forecasts. With the 2019 Forecasting Accuracy Report Summer Update[37], AEMO for the first time also included an assessment of the performance of supply forecasts, such as reliability of thermal generators. This will be expanded in the full 2019 Forecast Accuracy Report due later in 2019.

Based on the Forecasting Accuracy Reports' findings, AEMO develops and implements a workplan of improvements to its forecast data and methodology to address any issues identified. Improvements to both demand and supply forecasting, incorporated for the 2019 ESOO, are presented below.

AEMO has consulted extensively with industry stakeholders, primarily through its monthly Forecasting Reference Group (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 continued its collaboration with the Bureau of Meteorology (BoM) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) to better understand the impacts of extreme weather on supply and demand forecasting, now and in the future.

[36] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting.

[37] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/2019-Summer-Forecast-Accuracy-update.pdf.

1.5.1 Demand forecasting improvements

For the 2019 ESOO, AEMO has implemented a number of enhancements to its demand forecasts. These are explained in more detail in the updated Electricity Demand Forecasting Methodology Information paper[38] and are summarised below:

- Improved business sector consumption modelling – the overall sector has been segmented differently this year, to provide better visibility of consumption by large industrial users and better model performance of the remainder (commercial and smaller industrial sectors).
- Large industrial loads (informed by interviews and sector surveys) – these have been forecast separately from the econometric model this year, to remove the influence on the long-term econometric models from energy-intensive industries that are becoming increasingly less representative of the business sector.
- Energy efficiency savings – this year modelling has included consideration of EE savings from manufacturing small to medium enterprises, and methodological improvements have also been applied in apportioning existing and future schemes into the forecasts.
- Maximum/minimum demand forecasting – a hybrid methodology mixed detailed half-hourly models (capturing change in timing of extremes due to changes in technology mix) and an extreme value approach, focusing on high/low demand points only. This extreme value approach is new this year, and has been shown to be particularly accurate for the initial years in the forecast horizon.
- Battery charging – profiles have now been linked to solar availability, with 18 half-hourly historical reference years used to ensure the maximum demand model can capture weather-sensitive charge/discharge patterns.
- EV forecasts – through consultation with both energy and transport sectors, different segments and vehicle types are now captured and forecast separately, and a variety of charge profiles are used for each vehicle category, depending on the scenario settings.
- Energy efficiency impacts on maximum demand – the way EE measures are applied on extreme weather days has been updated, based on consultancy advice, reducing the projected impact of EE on maximum demand on extremely hot days.
- Demand traces – AEMO has made several improvements to the way demand traces are developed to meet the annual maximum demand targets. The new approach better captures the likelihood of peak demands in the months before and after summer. When building traces to meet high peak demand targets (10% POE targets), the new approach produces profiles which more resemble historical years where peak demand has been high.

1.5.2 Supply forecasting improvements

AEMO is continuously working to improve the accuracy of the forecasting assumptions and methodologies that underpin the modelling of supply adequacy. Through the development of the interim Reliability Forecasting Methodology, AEMO consulted with stakeholders on several improvements to supply forecasting which have been applied in this ESOO.

In general, the improvements in methodology are focused on more accurately forecasting both the expected conditions and the range of possible operational conditions that impact reliability in the NEM.

The modelling improvements, explained in more detail in the updated ESOO Methodology paper[39], include:

- Forced outage rate modelling – in previous ESOO modelling, the reliability of a scheduled generating unit was modelled using a single, expected set of forced outage parameters, based on the aggregate performance of its technology type. Historical analysis shows that even at the level of technology aggregations (Victorian brown coal, for example), the level of variability in reliability from year to year is

[38] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[39] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

significant. To better capture this range, the 2019 ESOO modelling sampled discretely from performance in each of the past four financial years. Furthermore, outage parameters have been applied at the station level to better capture the variability within these technology aggregations.

- Variable renewable generation – the contribution of variable renewable generation to reliability has been modelled using historical reference years which use the historical correlation between demand and wind and solar generation. The 2019 ESOO modelling added to the set of available reference years by including the 2018-19 financial year.
- Additional sensitivity analysis in the short term – due to operational considerations related to the return to service of units on long-term outages, the 2019 ESOO incorporated a number of sensitivities into its base case outlook. This resulted in a more realistic view of the range of possible conditions which will impact reliability in Victoria this summer. Further details are provided in Chapter 5.
- AEMO has continued to refine assumptions and methodologies across all areas of the modelling process, such as improvements to wind and solar generation modelling and comprehensive updates to the status of existing and potential new entrant generation through the Generation Information[40] survey process.

1.6 Additional information for 2019 ESOO

Table 3 provides links to additional information provided either as part of the 2019 ESOO accompanying information suite, or in related AEMO planning information.

Table 3 Links to supporting information

Information source	Website address and link
2019 ESOO supplementary results and data files	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 ESOO model and user guide	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 ESOO Constraints Workbook	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 ESOO Methodology Document	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Market modelling methodology report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
RRO Consultation and reliability forecasting methodology report	https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Reliability-Forecasting-Methodology-Issues-Paper
Demand Forecasting Methodology Information Paper	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Demand forecasting data portal	http://forecasting.aemo.com.au
Forecasting Accuracy Reporting	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting
Generation Information web page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

[40] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Information source	Website address and link
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
Medium Term Projected Assessment of System Adequacy (MT PASA)	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy
Integrated System Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

2. Trends in demand drivers

This chapter discusses the main drivers that affect electricity consumption and maximum demand today, and are expected to affect forecast levels in the outlook period.

Summary of key drivers

- Population is one of the main drivers of growth in electricity demand, directly affecting the number and type of residential and non-residential electricity connections. Australia's population is projected to grow at a faster rate in the short term than previously projected, attributed to both natural growth and immigration. AEMO's population growth forecasts incorporate the Australian Bureau of Statistics (ABS) 2016 census-based population growth projections, which feature increasing medium-term population growth of 1.6% per annum, before dropping to 1.2% in the long term (beyond 2032-33).
- Consumers are increasingly reliant on electricity. The uptake of household appliances continues to grow in the form of larger capacity white goods, larger televisions, more web-connected devices, and more heating and cooling capability. Similarly, the business sector has seen increased growth in heating and cooling needs, manufacturing capacity, computer hardware, data storage, and business-related appliances. As the uptake of EVs gains momentum over the coming years, and the electrification of other sectors of Australia's economy increases, reliance on electricity will continue to grow.

Despite the growing number of connections and increased reliance on electricity, growth in electricity consumption has been in decline across the NEM.

Continued growth in the uptake of embedded PV systems (rooftop PV and larger commercial PV 'non-scheduled' generation [PVNSG] systems) is reducing the electricity consumption and demand required to be met by the grid. Relatively strong growth in rooftop PV systems is forecast over the next five years while pricing support remains from high retail prices and government subsidies. Over the medium term, AEMO's forecasts capture likely growth in PVNSG incentivised by state/territory government incentives in Victoria, Queensland, and the Australian Capital Territory (ACT).

EE policies and measures also are acting to reduce electricity consumption, affecting both annual electricity consumption and the magnitude of peak electricity demands in the residential and commercial sectors. The impacts in the industrial sector are more modest, as policy support to date has focused on the residential and commercial sector. State energy savings schemes are currently scheduled to end between 2020 and 2030, with EE savings expected to decline, particularly after 2030, because post-2020 targets are yet to be set.

Weather continues to be a strong driver of customer demand and system supply, subject to short-term, medium-term, and long-term trends. Demand and supply forecasting processes simulate many weather years around a long-term climate trend. These simulations aim to capture all relevant weather trends including seasonal variability, El Niño/La Niña, and climate change. Climate change will have a greater effect on system maximum demand than on annual electricity consumption, by reducing heating load in winter and increasing cooling load in summer. AEMO has an active collaboration with the BoM and CSIRO and will continue to examine data and methods to consider the effects of climate change on all elements of the electricity system.

Updates to forecast drivers

For the 2019 ESOO, consumption and demand forecasts have been updated to capture the latest trends and projections of these key drivers. The main input changes compared to the 2018 ESOO include:

- Updated economic outlook provided by Deloitte Access Economics (Deloitte),
- Updated small-scale technology forecasts for EVs, battery storage systems, and PV systems (both rooftop PV up to 100 kilowatts [kW] and PVNSG between 100 kW and 30 megawatts [MW]) which were informed by forecasts provided by the CSIRO and Energeia.
- Updated energy efficiency and fuel switching forecasts, based on work prepared by Strategy. Policy. Research. (SPR).
- Updated retail electricity price outlook.
- Updated residential connections forecast.
- Updated large industrial consumption forecasts based on surveys and interviews with large energy users.
- Consideration of climate change within the long-term maximum demand forecasts, at a half-hourly level.

This chapter summarises some of these key input assumptions.

2.1 Economic and demographic outlook

2.1.1 Gross State Product

AEMO engaged Deloitte to develop long-term economic forecasts of each Australian state and territory as a key input to AEMO's demand forecasts, and consistent with the scenarios outlined in Section 1.4.

Deloitte's forecasts concluded that the short-term prospects for the Australian economy remain robust, with all states and territories expected to experience continued economic growth. Deloitte expects that solid economic growth is likely given that the global economic slowdown has been modest thus far, with central banks and governments quick to respond, and national income maintaining momentum.

In Deloitte's central scenario, Gross State Product (GSP) is forecast to grow at 3.1% annually on average across the NEM regions in the short term (0-5 years), spurred by public expenditure and a low Australian dollar. GSP is forecast to transition to an average long-term growth rate of 2.7% annually, driven by labour force and productivity growth. Productivity is expected to lift and wage growth is expected to pick up, with broad unemployment measures down and rates of underemployment starting to return to longer term averages.

Deloitte's weak economic outlook (aligned to the 2019 ESOO Slow Change scenario) assumes countries shy away from international engagement, resulting in less efficient allocation of resources. With a long-term annual average growth rate of 2.0%, economic growth is lower relative to Deloitte's central scenario. Lower real household disposable income growth flows through the economy affecting industry and economic growth: the Slow Change scenario examines lower levels of investment being made in technology advancements in DER, EE measures, and EVs.

In contrast, Deloitte's strong economic outlook (aligned to the 2019 ESOO Step Change scenario) is based on an increase in world Gross Domestic Product (GDP) growth, increase in population growth in Australia, productivity gains from skilled migration, and increases in international trade of goods and services. Economic growth is higher relative to Deloitte's central scenario, with a long-term average annual growth rate[41] of 3.3%. The forecast impact of these drivers in the Step Change scenario is an increase in overall discretionary income and investment in energy saving technologies and measures.

[41] Here, and elsewhere in this report, the average annual growth rate has been calculated as Compound Annual Growth Rate (CAGR).

2.1.2 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) electricity connections[42]. The number of new residential connections is also driven by social factors, such as changes to the household structure.

For the 2019 ESOO forecasts, AEMO updated its connections forecasts by applying the Housing Industry Association (HIA) dwelling forecasts, and both the ABS 2018 long-term population projections and the ABS 2019 household dwelling projections:

- In the first four years, the new connections forecast used the HIA dwelling completion forecasts.
- Beyond four years, AEMO applied ABS housing and population forecasts.

The Central scenario assumes population growth follows historical trends for mortality, and net overseas (and interstate) migrations, leading to average long-term population growth of 1.3%.

The Slow Change scenario assumes a lower life expectancy and net overseas migration relative to the Central scenario, and has an average annual growth of 1.1%.

The Step Change scenario assumes higher fertility rates, higher life expectancy, and net overseas migration, that drives higher population growth and an average annual growth rate of 1.6%.

Non-residential connections were forecast using the economic growth outlook in each state and territory, with the total number of connections projected to increase by about 1.1% per annum compounded over the 20-year outlook.

2.2 Distributed energy resources

DER describes small-scale embedded generation such as rooftop PV systems, PVNSG, battery storage, and EVs. AEMO commissioned CSIRO and Energeia to assist AEMO to produce DER forecasts for differing scenarios of the anticipated uptake rates and usage behaviours of various DER devices.

2.2.1 Rooftop PV and PV non-scheduled generation

Rooftop PV and PVNSG have continued to maintain strong growth over 2018 and early 2019, leading to approximately 1.4 gigawatts (GW) of new installations and bringing the total capacity of behind-the-meter[43] PV systems in the NEM to about 8.1 GW[44]. To put this in perspective, 8.1 GW is more than twice the capacity of Loy Yang A and Loy Yang B coal-fired power stations combined.

Figure 7 compares the uptake forecasts across the 2019 scenarios, and with the 2018 ESOO Neutral scenario forecast.

The 2019 Central scenario's rooftop PV forecasts follow a slightly lower trajectory than the 2018 forecast, with continued strong uptake through to 2021, driven by current retail prices and small-scale technology certificate (STC) subsidies[45].

This tapers off to a lower level of uptake later in the forecast period, due to the anticipated lengthening of the payback period caused by easing retail prices[46] as new large-scale renewable generation comes online, and STC subsidies reduce to zero by 2030.

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[42] AEMO assumes a single residential electricity connection for each completed dwelling over the 20-year forecast period.

[43] Behind-the-meter devices are on consumers' premises and connect to the distribution system.

[44] Installed capacity as at 30 June 2019, based on Clean Energy Regulator (CER) and Australian Photovoltaic Institute (APVI) data, unadjusted for degradation.

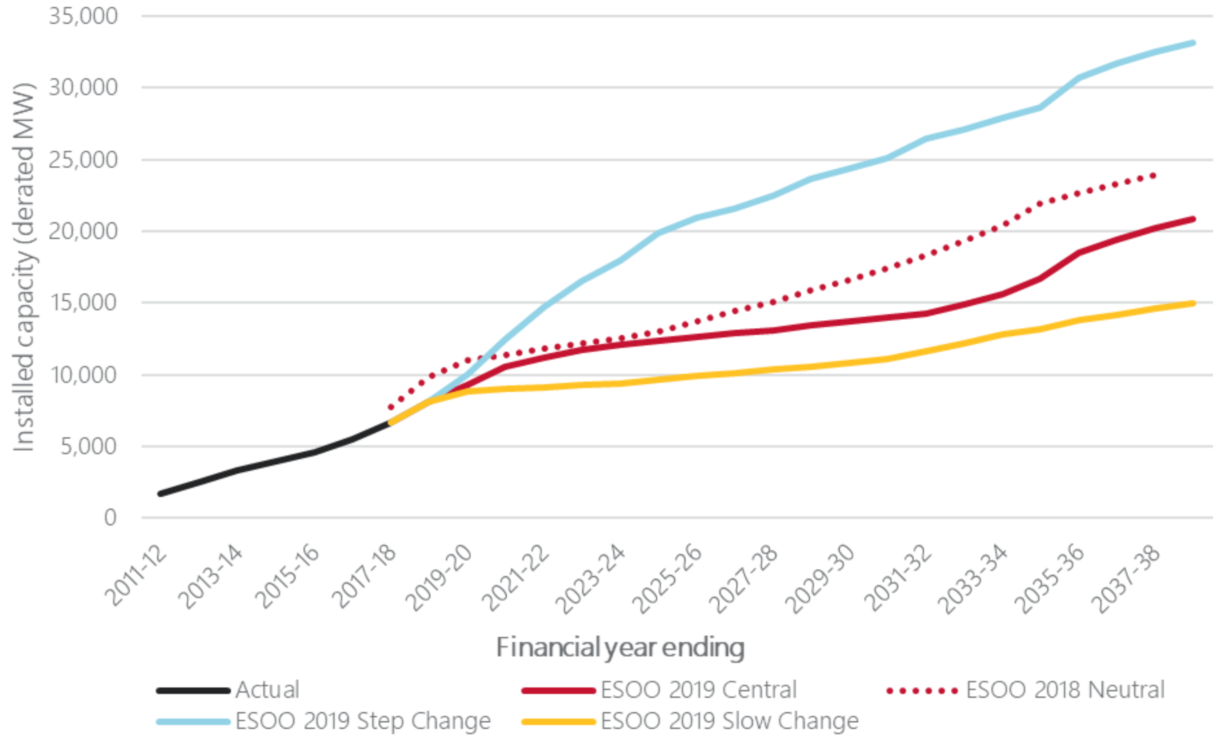
[45] See Section 3.1.4 of CSIRO (2019) Projections for small-scale embedded technologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[46] For more information on price assumptions, see Section 4.2 of CSIRO (2019) Projections for small-scale embedded technologies.

Growth is forecast to strengthen again in the mid-2030s, due to a moderate forecast increase in retail prices resulting from plant retirements, and the continued reduction of rooftop PV system prices.

The forecast slowing growth of rooftop PV over the 2020s is offset by projected uptake of PVNSG systems. While Large-scale Generation Certificate (LGC) prices are projected to approach zero in the next few years[47], state-based incentives are expected to help counter this in Victoria, Queensland, and the ACT[48].

Figure 7 NEM rooftop PV and PVNSG installed capacity comparison, actual and forecast



AEMO improved the method for calculating regional rooftop PV generation this year, engaging SolCast to provide 19 years of historical estimated generation, which influences the expected energy produced in forecast years. SolCast has provided AEMO with a data set that is more granular, both spatially and temporally, than the estimation estimates used previously.

2.2.2 Battery systems

Behind-the-meter residential and commercial battery systems have the potential to change the future demand profile in the NEM, and thus also maximum and minimum demand. The extent of these changes depends on a number of factors, including:

- The quantity, storage capacity (in kilowatt hours [kWh]), and charge/discharge power (kW) of batteries installed.
- The relative penetration of different tariffs and associated battery charge/discharge modes[49].

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47 Based on CSIRO analysis. See sections 3.1.4 and 5.1.3 of CSIRO (2019) Projections for small-scale embedded technologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

48 At the time CSIRO's 2019 projections were developed, these were the only states that had large-scale incentives in addition to LGC (Victoria's Renewable Energy Target [RET], ACT's Sustainable Energy Policy, and Queensland's RET). See Section 5.1.3 of CSIRO (2019) Projections for small-scale embedded technologies.

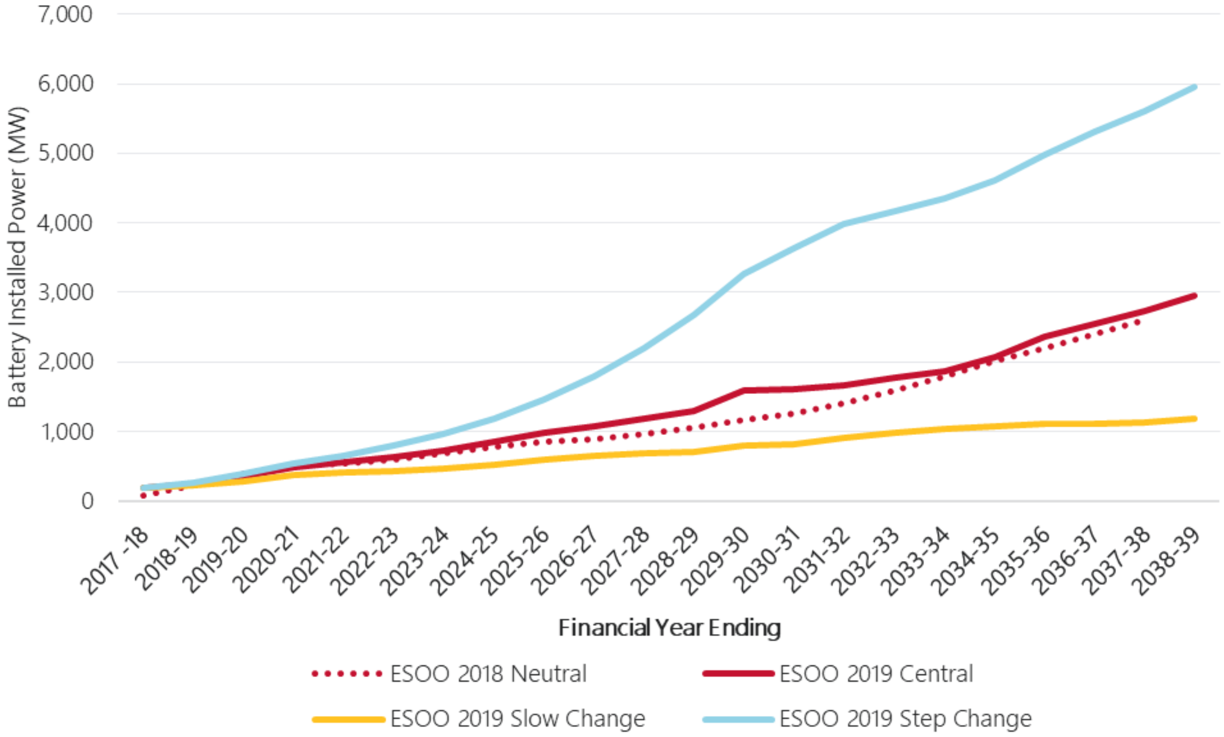
49 Battery operation modes may include behaviours to shift the over-supply of household energy from PV systems for consumption when household demand exceeds PV generation. Battery charge/discharge settings may allow or avoid grid consumption. Battery operation to maximise the benefits to retailers, aggregators, or the grid as a whole are all potential operating behaviours.

- The size of any complementary PV system and the energy consumption of the household or business.

The number of batteries currently installed in the NEM is not accurately known. The Clean Energy Regulator (CER) keeps a voluntary register of batteries, which presently indicates nearly 15,000 behind-the-meter battery systems are installed in the NEM[50]. However, as registrations are currently voluntary, the dataset is incomplete. AEMO's current work to implement the DER Register[51], along with collaboration with CSIRO in the National Energy Analytics and Research (NEAR) program[52], aims to improve the accuracy of this dataset in future.

For the 2019 ESOO, AEMO developed battery uptake and usage forecasts reflecting development drivers that are consistent with the scenarios. Figure 8 shows the total forecast installed capacity of batteries across the NEM for the three scenarios modelled, and compared with the Neutral forecast from the 2018 ESOO.

Figure 8 Behind the meter battery forecasts for the NEM



The Central scenario follows a similar trajectory to the 2018 ESOO forecast[53], with small variations due to revised assumptions including an increased estimate of the actual installed capacity, updated customer load profiles, and updated battery cost estimates[54]. Battery uptake is forecast to slow briefly as battery price reductions are expected to stabilise around 2030, while growth is projected to increase beyond 2032 due to forecast retail price increases.

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[50] CER data sourced on 31 July 2019 from http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

[51] For more information, see https://www.aemo.com.au/Stakeholder-Consultation/Consultations/NEM-Distributed-Energy-Resources-Information-Guidelines-Consultation.

[52] One research area in the NEAR program is to identify batteries that are not captured on CER's database. For more information on the NEAR program, see https://near.csiro.au/.

[53] In the 2018 ESOO, PV and battery forecasts were equivalent across all three scenarios.

[54] For further information, see the Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

2.2.3 Electric vehicles

Electrification of the transport sector could make a material contribution to electricity consumption in future. The extent of this contribution is uncertain, because uptake of EVs is still in the early stages, and information on current charging behaviour is relatively limited and may not be representative for future behaviour.

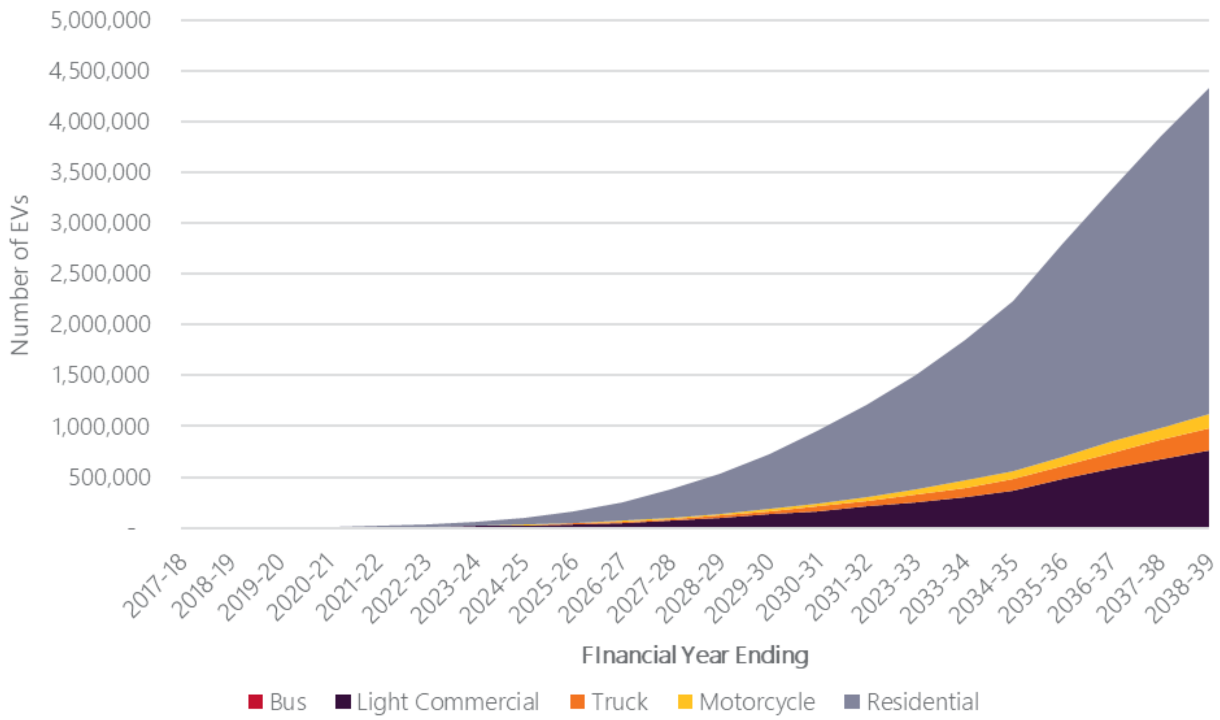
AEMO, through consultation with industry, has sought to identify key EV adoption factors. These include:

- Government policies.
- The levelised cost compared to current vehicles.
- Substitutes and alternatives to EVs (such as public transport and hydrogen).
- Commercial fleet ownership.
- Access to charging infrastructure.
- The availability of different EV models in Australia.

Across the scenarios, as a result of these uncertainties, AEMO's forecast includes a large EV uptake spread affecting electricity consumption and maximum and minimum demand. AEMO is developing a roadmap to increase coordination between transport and energy sectors. Initially this should focus on developing a common approach to forecasting – developing datasets, sources, and assumptions that are key for EV adoption and charging factors – which should help reduce the uncertainty that emerging transport electrification provides for forecasters and planners.

CSIRO reports that EVs presently represent less than 1% of car sales in the NEM. Based on the current level of uptake, and in the absence of any policy incentives, CSIRO projects that the uptake of EVs will reach 4% in the next decade, a projection of over half a million EVs to be in use across the NEM in 2028-29[55]. Figure 9 shows the projected uptake by vehicle type, with residential vehicles forecast to be the largest EV sector, followed by light commercial vehicles and trucks.

Figure 9 NEM forecast number of EVs by vehicle type, Central scenario, 2017-18 to 2038-39



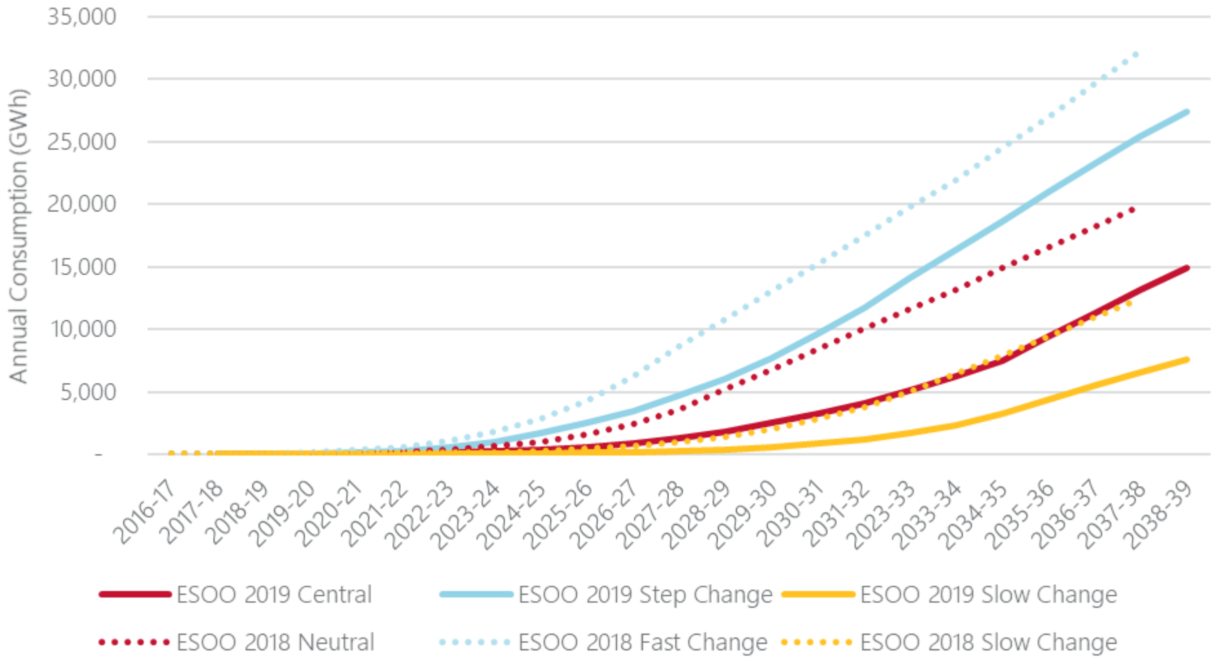
[55] CSIRO, 2019 Projections for small-scale embedded technologies report, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

After 2028-29, EV ownership is projected to start increasing faster, due to greater model choice, charging infrastructure availability, and falling costs through economies of scale and fuel savings. As a result, electrification of the transport sector is projected to accelerate in the late 2020s and into the 2030s.

In the Central scenario, nearly four and a half million residential and commercial EVs NEM-wide are forecast by 2037-38, representing approximately 17% of the total vehicle fleet. The 2018 ESOO, in contrast, forecast six million EVs by 2037-38, reflecting a higher projection for national vehicle sales, the exclusion of a competing technology (fuel cell vehicles), and faster vehicle cost parity.

Based on these uptake projections, Figure 10 shows the forecast annual consumption attributed to EVs across the NEM in the next 20 years, across all scenarios and compared to the three scenarios in the 2018 ESOO.

Figure 10 NEM EV annual consumption forecast, 2016-17 to 2038-39, all scenarios, compared to 2018 ESOO



The method and frequency of EV charging will impact the daily load profile. Charging is likely to be influenced by the availability of public infrastructure, tariff structures, energy management systems, and the driver's routine.

For this 2019 ESOO, AEMO has incorporated four charge profiles in the 2019 forecasts:

- Convenience charging – vehicles assumed to have no incentive to charge at specific times, resulting in greater evening charging after vehicles return to the garage.
- Daytime charging – vehicles incentivised to take advantage of high PV generation during the day, with available associated infrastructure to enable charging at this time.
- Night-time charging – vehicles incentivised to take advantage of low night-time demand.
- Highway fast charging – vehicles that require a fast charging service while in transit, based on a mix of simulated and actual arrivals of vehicles at public fast charging from CSIRO research.

Charge profile preferences are forecast to change over time. The increasing electrification of the transport sector is expected to lead to greater charging infrastructure development and tariff change, providing consumers with greater choice to charge their vehicles in ways that are increasingly convenient, while minimising grid cost and impact. As a result, AEMO anticipates growth over time in charging behaviour aligned to times of low overall demand, such as when rooftop PV generation is high.

Figure 11 and Figure 12 below show examples of the forecast contribution to demand from EV charging.

Figure 11 **Average weekday EV demand by charge profile type assumed for the Central scenario in January 2039 in New South Wales**

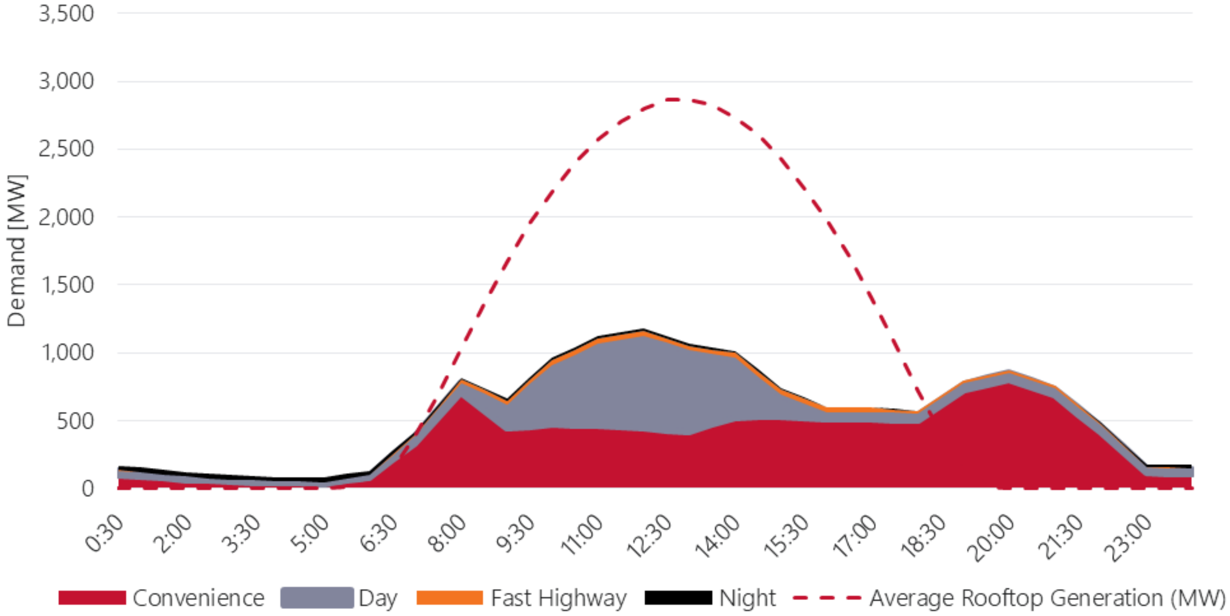
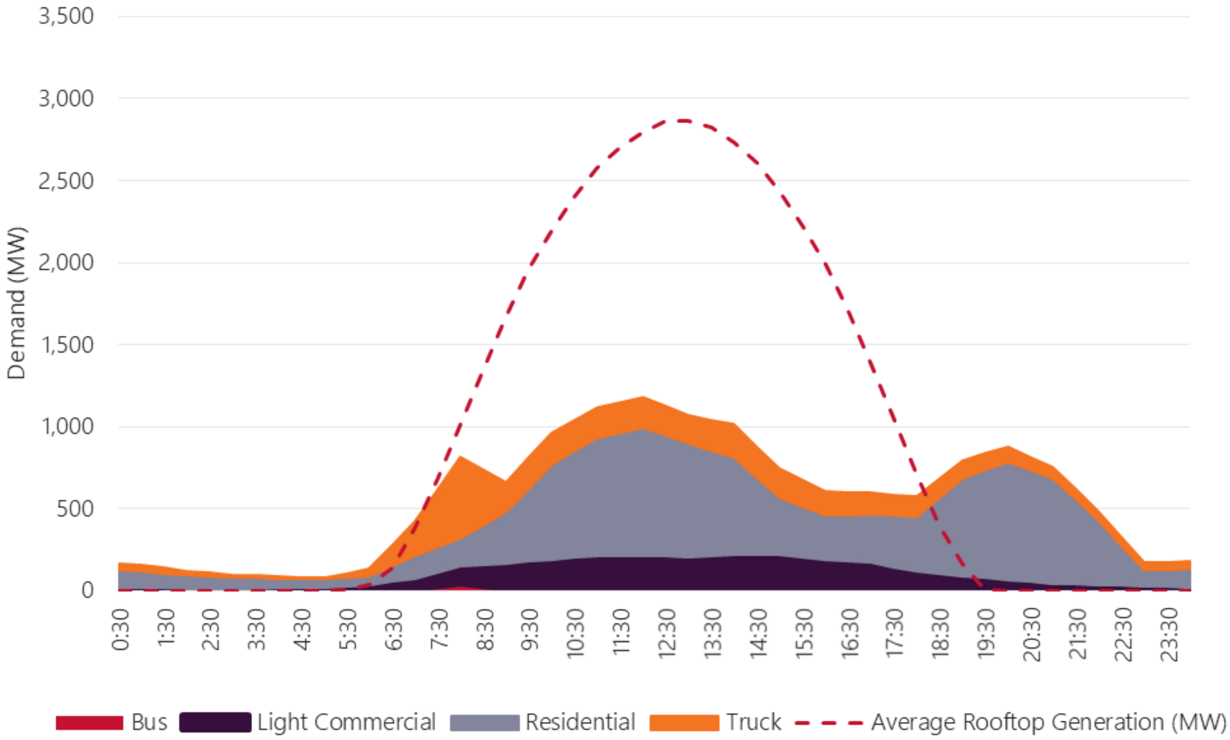


Figure 12 **Average weekday EV demand by vehicle type assumed for the Central scenario in January 2039 for New South Wales**



Note: Motorcycles are not shown in charging profiles, as their assumed electricity consumption is less than 0.5% of residential cars.

Each example considers these charging profiles for summer 2039 for a specific region and scenario, to show the contribution from charge profiles and vehicle category respectively. For detailed weightings of the various charge profiles applied to each scenario, refer to the 2019 Inputs and Assumptions workbook[56].

[56] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

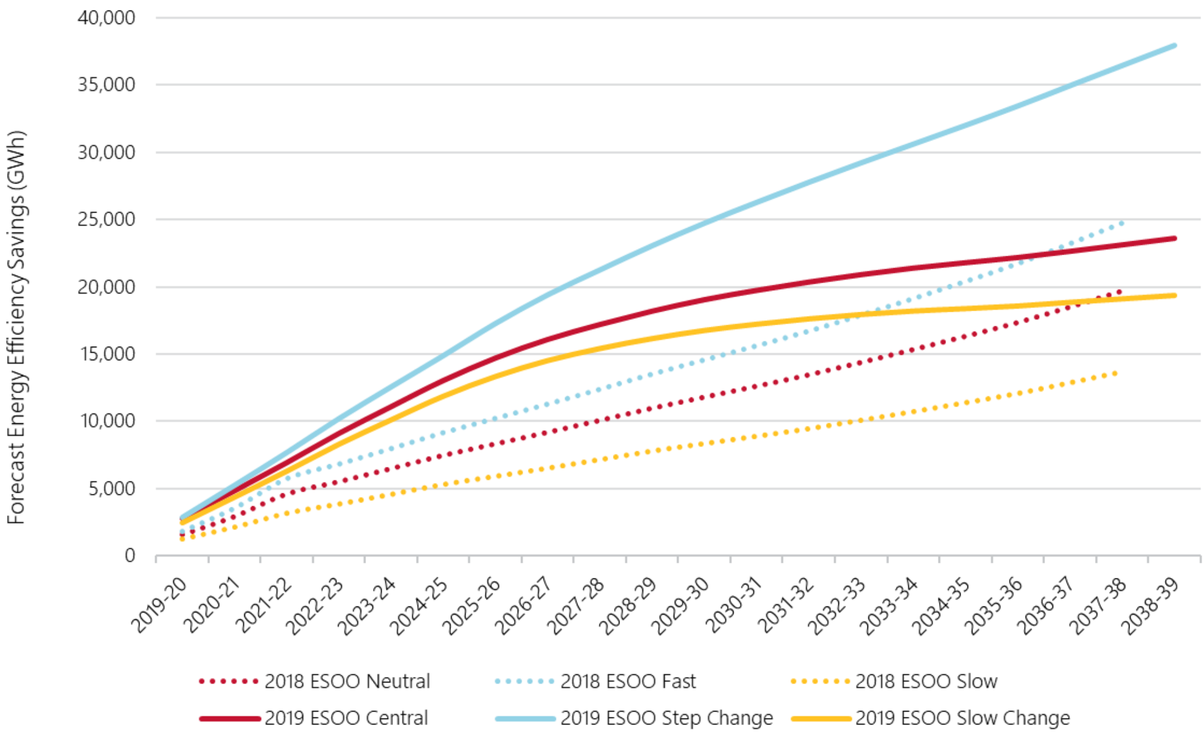
2.3 Energy efficiency and consumer behavioural response

2.3.1 Energy efficiency

EE means using less energy to achieve the same outcome[57]. The Commonwealth Government and state governments have developed measures to mandate or promote EE uptake across the economy, and AEMO has considered the impact of these measures on forecast electricity consumption.

AEMO's 2019 forecast includes more EE savings than forecast in 2018, as shown in Figure 13. The increased savings are largely due to the inclusion of savings from manufacturing small to medium enterprises (SMEs) this year, and methodological improvements affecting the EE forecasts of SME and residential segments[58].

Figure 13 Forecast energy efficiency savings, 2019-20 to 2038-39 and compared to 2018 ESOO



In the Central scenario, savings equate to 23.6 terawatt hours (TWh) from the 2018-19 base year, or approximately 10% less energy consumption by 2038-39 than would otherwise have been observed. Additional measures, representing feasible yet ambitious future standards for buildings and equipment[59] to drive greater EE savings, are included in the Step Change scenario, resulting in approximately 38 TWh of forecast EE by 2038-39. The Slow Change scenario is forecast to deliver 19.3 TWh of savings by 2038-39 and assumes similar EE measures as the Central scenario, under lower economic and population growth settings.

AEMO engaged SPR to assist in developing EE forecasts for the residential, commercial, and industrial sectors[60]. AEMO made several adjustments to SPR's forecasts, based on subsequent discussions with state

[57] From https://www.energy.gov.au/government-priorities/energy-productivity-and-energy-efficiency (viewed 25 July 2019).

[58] For more details, see Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[59] The two measures include future changes to the National Construction Code and activities under the Equipment Energy Efficiency program that are in proposal stage, or are currently suspended but could be reactivated.

[60] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

governments and to correctly apportion the savings to the SME and residential models. The adjustments are described in the Electricity Demand Forecasting Methodology Information Paper[61].

The forecasts include the following measures:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2006, BCA 2010, the National Construction Code (NCC) 2019, and, for the Step Change scenario, higher building performance requirements in the future.
- Building rating and disclosure schemes such as the 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 different classes of appliances and equipment. The Step Change scenario also considers additional measures that are in proposal stage or are currently suspended but could be reactivated.
- State-based schemes, including the New South Wales Energy Savings Scheme (ESS), the Victorian Energy Upgrades (VEU) program, and the South Australian Retailer Energy Efficiency Scheme (REES).
- Former Commonwealth Government programs that were not considered in the 2018 ESOO, including The Home Insulation Program and Energy Efficiency Opportunities Program.

The impact of state schemes is evident in the short term, although this tapers from the mid-2020s to 2030s, in conjunction with legislated end dates[62]. AEMO assumes that 75% of scheme savings persist beyond end dates until 2039. The NABERS and CBD programs are also expected to saturate in uptake, and their forecast energy savings fall from the mid-2020s.

In the medium to longer term, energy savings increase at a slower rate for the Central and Slow Change scenarios. In both scenarios, the Greenhouse and Energy Minimum Standards (GEMS) program provides modest savings, and NCC-related savings are a function of net growth in residential dwellings and commercial building stock. For the Step Change scenario, the two additional measures related to higher building and equipment standards deliver stronger savings to 2039 than in the Central and Slow Change scenarios.

2.3.2 Fuel-switching

AEMO has incorporated fuel-switching in the EE forecasts for 2019, as the effects of both demand drivers are intertwined.

Based on current trends, SPR assumed a shift from gas to electricity for space conditioning. In the residential sector, for example, reverse-cycle air-conditioning is expected to reduce gas demand that could have arisen due to gas heating. In the commercial sector, the EE forecasts adopt fuel mix assumptions from building code regulation impact statements.

There are, however, counter-effects from EE measures that target a reduction in carbon emissions, rather than energy savings. For example, the VEU program has historically resulted in a shift from electricity to gas consumption[63]. The NCC is also forecast to result in a modest increase in gas water heating in Victoria, additional to the effects of other EE measures in the state.

The EE forecasts include the 'net effect' of this fuel-switching behaviour.

2.3.3 Consumer behavioural response

Electricity prices are assumed to initiate both structural changes by consumers, such as decisions to purchase DER, and behavioural changes, such as how electricity devices are used or energy consumption is managed.

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[61] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[62] Current legislated end dates: SA REES: 2020, NSW ESS: 2025, and VEU: 2030.

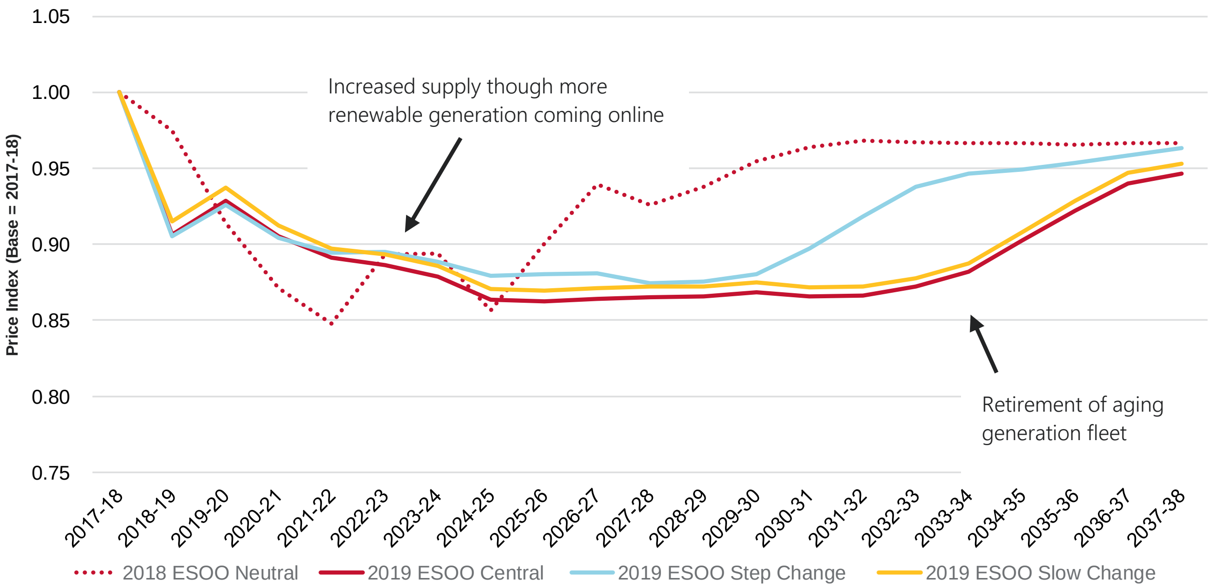
[63] This historical trend may change in future. See SPR report for further details, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

DER can similarly initiate behavioural change; the 'PV rebound effect' has been observed, where households with installed rooftop PV are likely to increase consumption due to lower electricity bills.

Consumer responses to price changes are modelled through consumer behavioural response. Consumption forecasts consider the price elasticity of demand (that is, the percentage change in demand for a 1% change in price), applying the same method as the 2018 forecast[64].

The 2019 ESOO price forecasts were formed from bottom-up projections based on separate forecasts of the various components of retail prices. The retail price structure followed the Australian Energy Market Commission (AEMC) 2018 Residential Electricity Price Trends[65] report, and the wholesale price forecasts were prepared for AEMO by Aurora Energy Research[66]. Additional transmission development costs associated with AEMO's ISP central development plan also impact the total cost. Figure 14 shows the resulting residential retail price index.

Figure 14 Residential retail price index, NEM (connections weighted)



* Price weighted by the number of households.

As Figure 14 shows, prices across the NEM are forecast to decline in the medium term, as more renewable generation comes online lowering wholesale prices, and to increase in the long term as the aging coal fleet retires.

2.4 Weather and climate

Customer demand and system supply are highly responsive to weather, which is subject to short-term, medium-term, and long-term trends. Demand and supply forecasting processes are not fitted to a specific weather prediction, but instead simulate many weather years around a long-term climate trend. These simulations aim to capture all relevant weather trends, including seasonal variability, El Niño/La Niña, and climate change.

AEMO formally collaborates with the BoM and CSIRO to improve its modelling of weather and climate trends. Through this collaboration, further work is underway so the effects of climate change on all elements of the

[64] AEMO 2018 Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

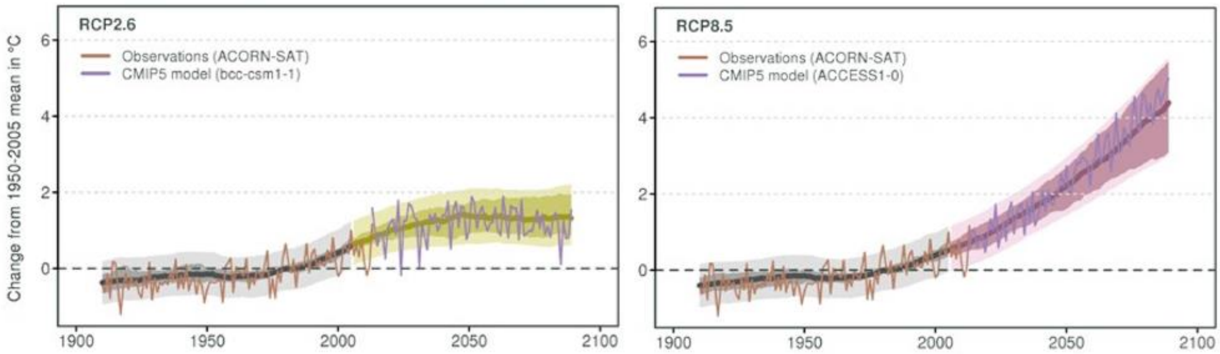
[65] AEMC, 2018 Residential Electricity Price Trends, at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2018.

[66] Aurora, Energy Research analysis of AEMO's ISP Part 1: benefits of interconnection, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

electricity system will be considered. Impacts on customer demand have been considered since 2018, while impacts on generator supply and system availability will be implemented after the 2019 ESOO.

The three ESOO scenarios consider varying atmospheric carbon concentrations, impacting the degree of climate change. Average temperature increases vary substantially between scenarios in the long term, as shown in Figure 15, which shows the projected mean Australian temperature for the Step Change scenario (RCP2.6) and the Slow Change scenario (RCP8.5).[67]

Figure 15 Time series for Australian average temperatures as simulated relative to 1950-2005 mean



Source: https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/168/CCIA_2015_NRM_TR_Chapter%207.pdf.

With the help of the BoM and CSIRO, AEMO uses publicly available projections data[68] to downscale and project half-hourly temperature data per region. The half-hourly methodology recognises that climate change impacts minimum, average, and maximum temperatures differently.

Climate change 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.

[67] For more information on Representative Concentration Pathways (2.6, 4.5, 6.0, 8.5) see https://www.climatechangeinaustralia.gov.au/en/publications-library/technical-report/. Additional RCPs (1.9, 3.4, 7.0) are emerging through work by the Intergovernmental Panel on Climate Change (IPCC) sixth assessment due to be published in 2020-21 and are developed on a comparable basis.

[68] At www.climatechangeinaustralia.gov.au.

3. Demand forecasts

Based on the key input drivers in Chapter 2, AEMO has forecast operational electricity consumption and maximum and minimum demand for the next 20 years. These drivers interact in ways that result in operational maximum demand growing faster than operational consumption.

3.1 Annual consumption forecasts for the NEM

Key insights

- Australia's population increase is expected to be the main driver of underlying consumption for the residential sector, and along with mining activity, is a key contributor to economic and consumption growth in the business sector. However, expected increases in energy productivity and energy efficiency, continuing structural change in the economy away from energy-intensive industries, and further increases in rooftop PV installations are expected to temper growth in both annual operational consumption and maximum demand in the next 10 years.
  - In the short term (0-5 years), growing DER and EE is forecast to lead to a slight overall reduction in operational consumption, from 182 TWh in 2018-19 to 178 TWh in 2024-25 (-0.4% average annual growth rate).
  - In the medium term (5-10 years), forecast uptake of EVs introduces a new demand sector for the NEM, the continuing impact of state-based EE schemes is projected to decline, and other DER investments are forecast to slow. This results in a slight forecast increase in operational demand, from 178 TWh in 2024-25 to 179 TWh (0.1% average annual growth rate) by 2028-29.
  - In the long term (10-20 years), although forecast PV installation rates begin to increase, all EE forecasts begin to saturate, and EVs are projected to become a key driver for continued operational consumption growth, with consumption forecast to increase from 179 TWh in 2028-29 to 191 TWh by 2038-39 (0.6% average annual growth rate).
- In the Step Change scenario, higher economic activity, population growth, and greater electrification of the transport sector are forecast to be balanced by consumer-led investment in PV, EE measures, and a greater orientation towards economic activity from less energy-intensive manufacturing activities. These drivers lead to forecast operational consumption being marginally lower at 191 TWh (-0.2%) under this scenario by 2038-39 than under the Central scenario (numbers are rounded).
- In the Slow Change scenario, lower economic activity and population growth reduces the forecast, although PV growth is also slower. This scenario also captures some closures of at-risk energy-intensive sectors of the economy. Operational consumption for the Slow Change scenario is significantly lower, at 155 TWh (-19%) by 2038-39, than under the Central scenario.
- The 2019 Central scenario is forecast to be lower than the 2018 Neutral projections by about 9% by the end of the 20-year horizon. The primary drivers for these reductions, relative to 2018 trajectories, are stronger forecast growth in EE savings, lower EV impact, and improved representation of structural shifts in energy consumption affecting the business sector.

AEMO's component-based forecast methodology projects the range of complex dynamics that affect electricity consumption growth and are calibrated against the most recent meter data available. The components are selected based on commonality of key drivers and data accessibility.

Figure 16 shows the magnitude of these components in the forecast, including those components projected to reduce operational consumption, such as DER and EE activities.

Figure 16 NEM electricity consumption, actual and forecast, 2006-07 to 2038-39, Central scenario

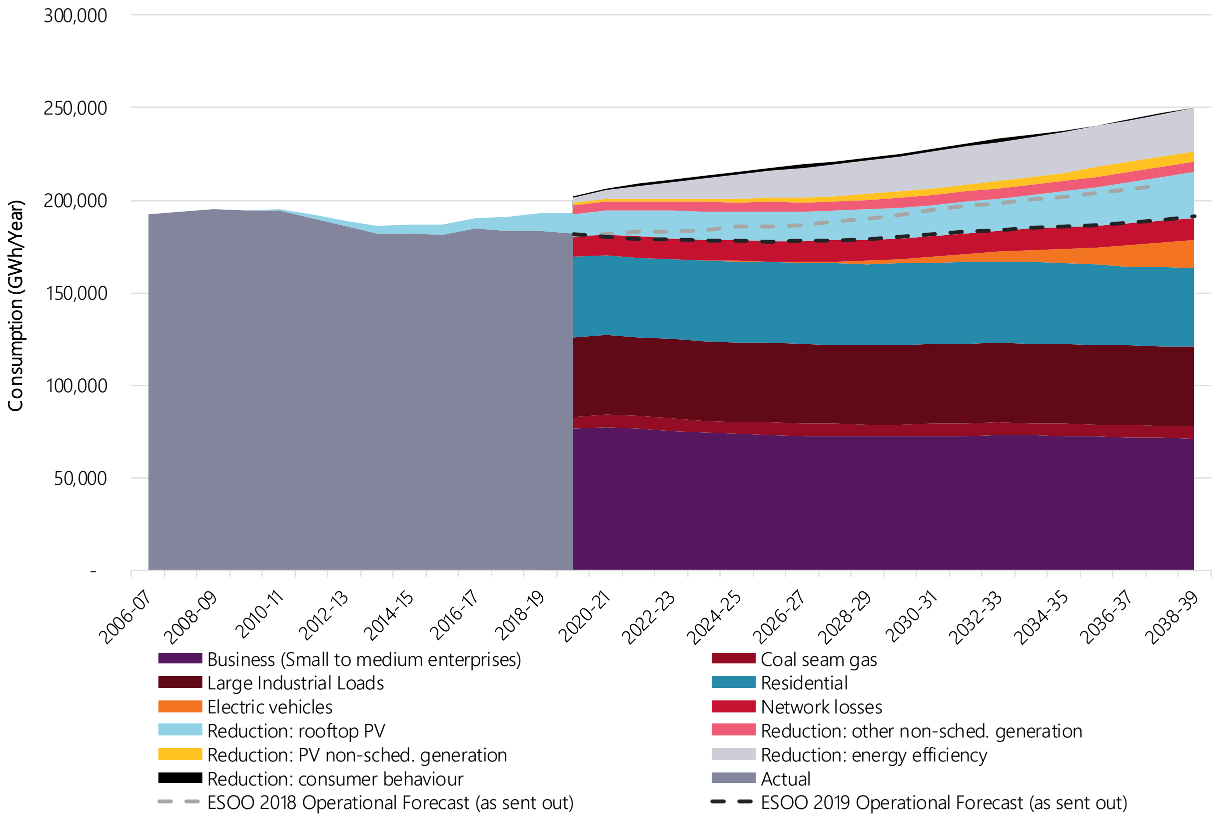
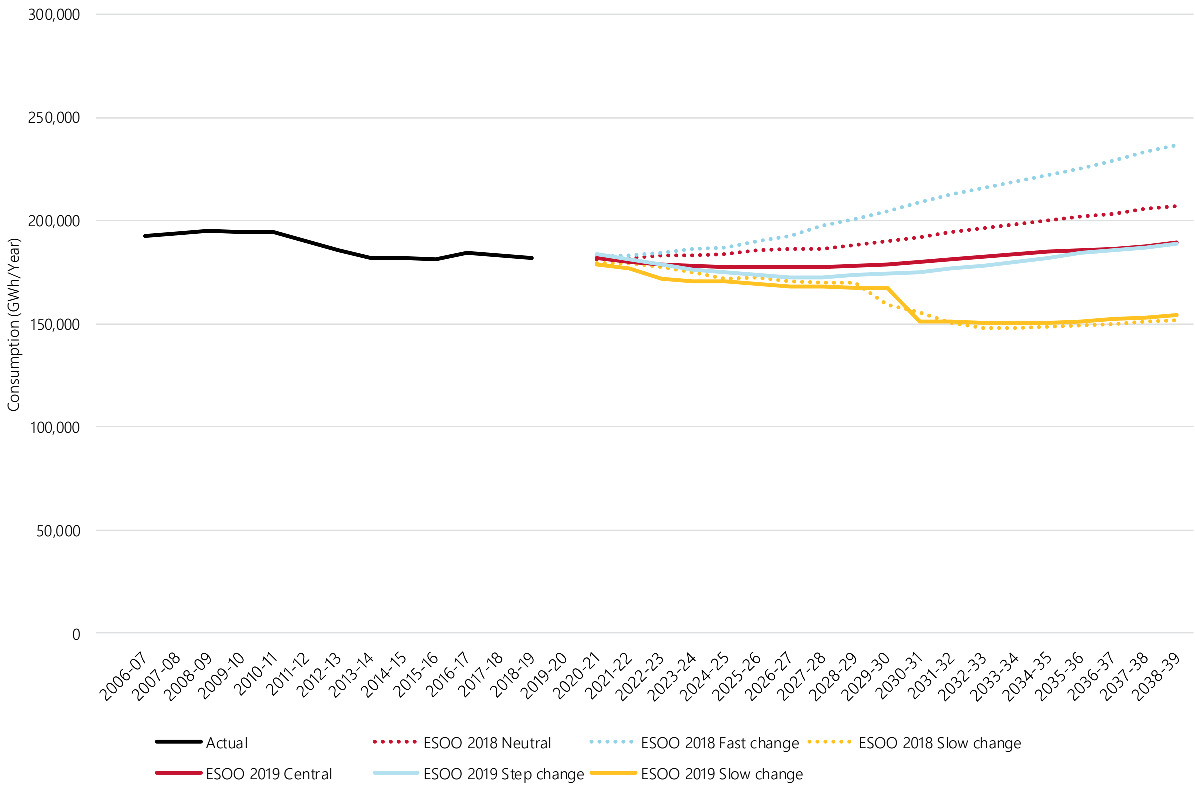


Figure 17 compares the 2019 ESOO forecasts for annual consumption and the 2018 ESOO forecasts across the scenarios in both forecasts. Differences include:

- The impact of a revised business sector forecast approach that increases the emphasis on the SME sector, with greater de-coupling of large industrial consumers. This better reflects Deloitte's economic outlook with economic growth predominantly driven by growth in population and the services sectors, and results in less consumption growth forecast in the 2019 ESOO Central and Step Change scenarios. Despite greater breadth in the scenario narratives and potential future worlds, the resultant operational consumption dispersion is narrower this year.
- The 2019 Step Change scenario includes higher forecast EE savings, with more measures included than were considered in the 2018 Fast Change scenario, along with higher PV forecasts. Together these factors result in a much lower forecast outlook in the long term.
- Further regional details are provided in Appendix A1.

Figure 17 Forecast NEM operational consumption as sent out, actual and forecast, all scenarios, 2006-07 to 2038-39, for the 2019 ESOO and compared to the 2018 ESOO



3.1.1 Residential sector forecasts

Key insights

- Consumers are continuing to take an active role in managing energy consumption, with the current level of residential rooftop PV installations estimated to have reduced grid consumption in the NEM by 7.7 TWh for 2018-19. Continued adoption of more energy-efficient appliances and dwelling improvements has further reduced consumption, with an estimated 0.8 TWh of additional EE savings achieved in the last financial year alone[69].
- In the forecasts:
  - In the short term (0-5 years), residential underlying consumption is projected to rise, with an average annual growth rate of 1.4% by 2024-25. This is driven by projected population growth and appliance uptake and usage, including a growing trend of switching from gas to electric appliances. Growth in underlying consumption would be even stronger if not tempered by greater investment in more efficient appliances and other EE measures. However, this growth in underlying consumption is not expected to translate into consumption growth on the grid, as rooftop PV growth reduces operational consumption, and delivered electricity to the residential sector is expected to decrease with an average annual growth rate of -0.1% during this period.
  - In the medium term (5-10 years), forecast underlying consumption continues to grow, at an average annual growth rate of 1% from 2024-25 to 2028-29. This is lower than the short-term rate, due to the impact of more efficient appliances and dwelling investments. Projected slower rooftop PV uptake, a rise in the number of new connections, and growth in EV ownership lead to a forecast net increase in delivered consumption, at an average annual growth rate of 0.9%.

[69] Based on SPR's estimate of savings.

- In the long term (10-20 years), underlying consumption is expected to increase, with an average annual growth rate of 2.1% from 2028-29 to 2038-39, largely due to forecast accelerating growth in EVs. This growth is projected to be partially offset by PV uptake and EE activities, with a forecast average annual growth rate of 1.5% in delivered electricity to the residential sector.

- Compared to the Neutral forecast in the 2018 ESOO, the 2019 Central delivered energy forecast is about 9.5% lower by the end of the 20-year forecast horizon, mainly due to stronger PV uptake, greater EE savings, and lower EV uptake now forecast.

AEMO's residential forecast model is similar to that applied for the 2018 ESOO, with the main drivers and inputs updated, including new connections, rooftop PV, batteries, EVs, appliance uptake and usage, EE impacts, climate change, price, and consumer behavioural response (as outlined in Chapter 2).

Figure 18 shows forecasts for underlying and delivered consumption for the 2019 Central scenario in the residential sector, highlighting that PV and EE activities are projected to temper the growth in grid consumption that would otherwise be expected from connection growth. In the 2019 Central scenario, the number of connections is forecast to increase from 101.2 million in 2018-19 to 129 million in 2038-39 (1.2% average annual growth rate). In the Step Change scenario, the connection forecast is higher (1.6% average annual growth rate), while in the Slow Change scenario the projected growth in connections is lower (0.9% average annual growth rate).

Figure 18 Forecast underlying demand, delivered demand (sourced from grid), rooftop PV, and additional energy efficiency savings for Central scenario

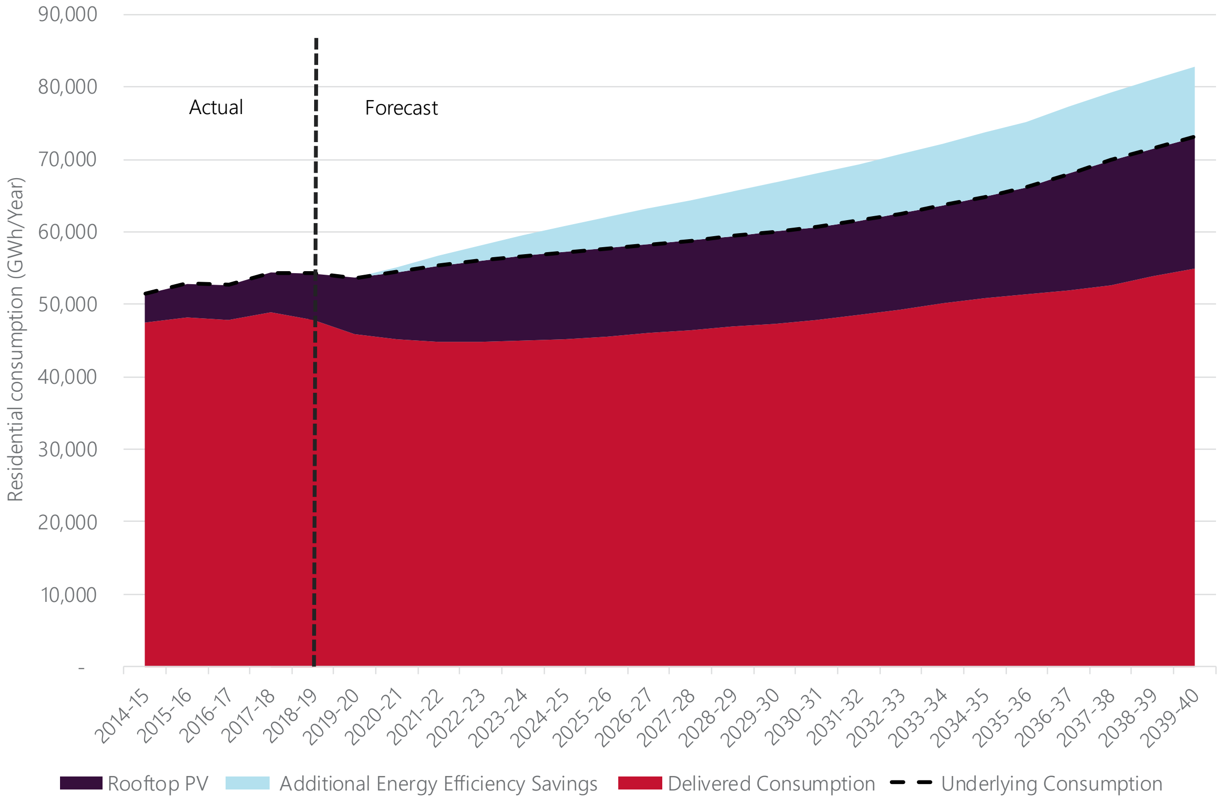
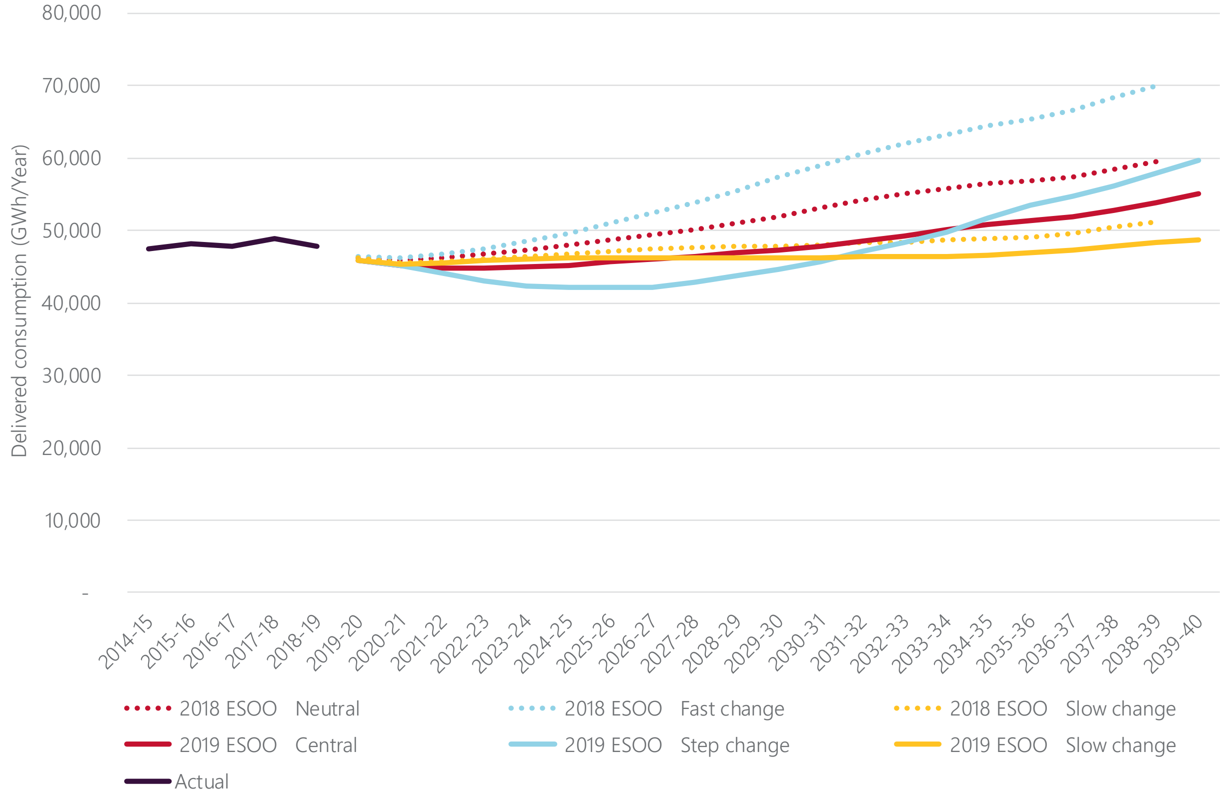


Figure 19 shows the residential forecast across the 2019 ESOO scenarios compared to the 2018 ESOO scenarios, and actual delivered demand. The forecast trajectory for all three scenarios in the 2019 ESOO is lower than the 2018 ESOO scenarios, mainly due to projections of stronger PV uptake, greater EE savings, and lower EV uptake. The scenario narrative for the Step Change scenario with respect to the rate of decarbonisation and decentralisation of the NEM also differs significantly from the 2018 Fast Change scenario, so direct comparisons of results should be interpreted with caution.

Figure 19 NEM delivered residential electricity consumption forecast, all scenarios, 2019 to 2039, compared to the 2018 ESOO



As shown in Figure 19:

- Delivered residential electricity consumption in the Slow Change scenario remains relatively stable in the short to medium term, due to lower forecasts for new dwellings, less increase in the electricity retail price, and lower uptake of rooftop PV, EVs, and EE than the Central scenario. Consumption in the Slow Change scenario is forecast to increase slightly in the medium to long term, due to projected EV uptake (see Section 2.2.3). This results in a forecast average annual growth rate of 0.3% in the delivered demand for the residential sector by the end of 2038-39 compared to 2018-19 in this scenario.
- The Step Change scenario forecast reflects higher new dwellings and EV growth compared to the Central scenario, but also greater DER and EE measures. Delivered residential consumption in the Step Change scenario is forecast to decline in the short term, due to this stronger uptake of rooftop PV and additional measures increasing EE savings. By the end of 2025-26, there is an average annual reduction rate of -1.4% forecast in residential delivered demand compared to 2018-19, resulting from a combination of these drivers. Over the medium to long term, delivered consumption is expected to increase, as forecast growth of new dwellings and stronger EV uptake is forecast to offset the declining projected impacts of rooftop PV and EE. As a result, the Step Change forecast starts below both the Slow Change and Central forecasts, but crosses over these forecasts between 2029-30 and 2033-34 respectively.

3.1.2 Business sector forecasts

Key insights

- Growth in business consumption mainly follows increases in population and business activity, and with both projected to rise, business consumption is forecast to increase. Growth in EVs is also expected to provide a new source of business electricity consumption. Continuing structural changes towards less energy-intensive sectors, rising EE forecasts, and increased PV, however, reduce or offset growth in annual delivered energy.
- Delivered energy for the business sector is projected to grow slightly at an annual average rate of approximately 0.2% in the Central scenario, with total business consumption projected to be 135 TWh in 2038-39 compared to 131 TWh in 2018-19.
  - In the short to medium term (0-10 years), business consumption is expected to be relatively flat, as increased economic activity and population growth and forecast EV demand of 0.7 TWh in this period are projected to be offset by increased PV investment and growth in EE savings of 11.4 TWh incentivised through existing schemes in Victoria, New South Wales, and South Australia.
  - In the long term (10-20 years), business consumption is expected to grow slightly. PV investment is expected to increase (reducing consumption) as price increases provide greater incentive for this investment, but EE savings are forecast to taper off (an additional 2.4 TWh of EE savings forecast in this period) and transport sector electrification is projected to provide a new source of load (an additional 5.3 TWh in consumption growth from EVs).
- Compared to the 2018 Neutral trajectory in the 2018 ESOO, the 2019 Central delivered energy forecast is about 8% lower by the end of the 20-year forecast horizon. This is mainly due to forecast greater EE savings, lower EV uptake, and reduced consumption from energy-intensive industry.
- The 2019 Step Change forecast is similar to the Central scenario. The projected impact of higher economic activity, electrification of the transport sector, and population growth is offset in this scenario by higher EE measures and lower forecast consumption by energy-intensive industry. Greater impacts from these factors, and forecast higher uptake of small-scale embedded technologies, result in lower projected consumption than was forecast in the 2018 ESOO Fast Change scenario.
- The 2019 Slow Change scenario highlights greater downside risk for energy consumption in the business sector. This Slow Change scenario models lower economic activity and population growth and assumed vulnerability for some large industrial loads (LIL) in the short to medium term, with some potential closures in the forecast. The outlook is similar to the 2018 Slow change scenario.

AEMO's approach to forecasting the business sector separates large industrial loads (LIL) and energy-intensive industries (including coal seam gas [CSG], which is forecast separately) from small to medium enterprises (SME). These sectors are defined as follows:

- LIL – traditional manufacturing businesses, coal mining, and other large energy users including desalination plants. These loads are now forecast separately so the largest energy users are independently assessed, allowing other business consumers to be forecast using more targeted econometric models that exclude the separate drivers affecting large industrial loads.
- CSG – electricity consumption associated with the operation of CSG wells, including compressor plant to transport the CSG to liquefaction plant to convert to liquefied natural gas (LNG) for export.[70] The CSG sector is only present in the Queensland region.
- SME – predominantly services-based businesses and smaller manufacturing businesses not part of the other two categories (generally sites that have demand less than 10 MW). The electricity loads associated

[70] CSG liquefaction load is not part of the CSG forecast. The Gladstone liquefaction plant has on-site generation and does not draw energy from the grid.

with distribution-connected railways are part of the SME aggregate, although some transmission-connected railway loads associated with mining are captured in the LIL sector.

Drivers affecting these three sectors are discussed separately later in this section.

Figure 20 shows the overall trend in forecast business consumption for the Central scenario compared to the 2018 ESOO Neutral scenario demand forecast. As the figure shows, the underlying consumption trend is lower than forecast in 2018, with EE savings growth being larger in 2019 than the 2018 forecast.

Figure 20 NEM underlying business electricity consumption forecast, Central scenario, 2018-19 to 2038-39

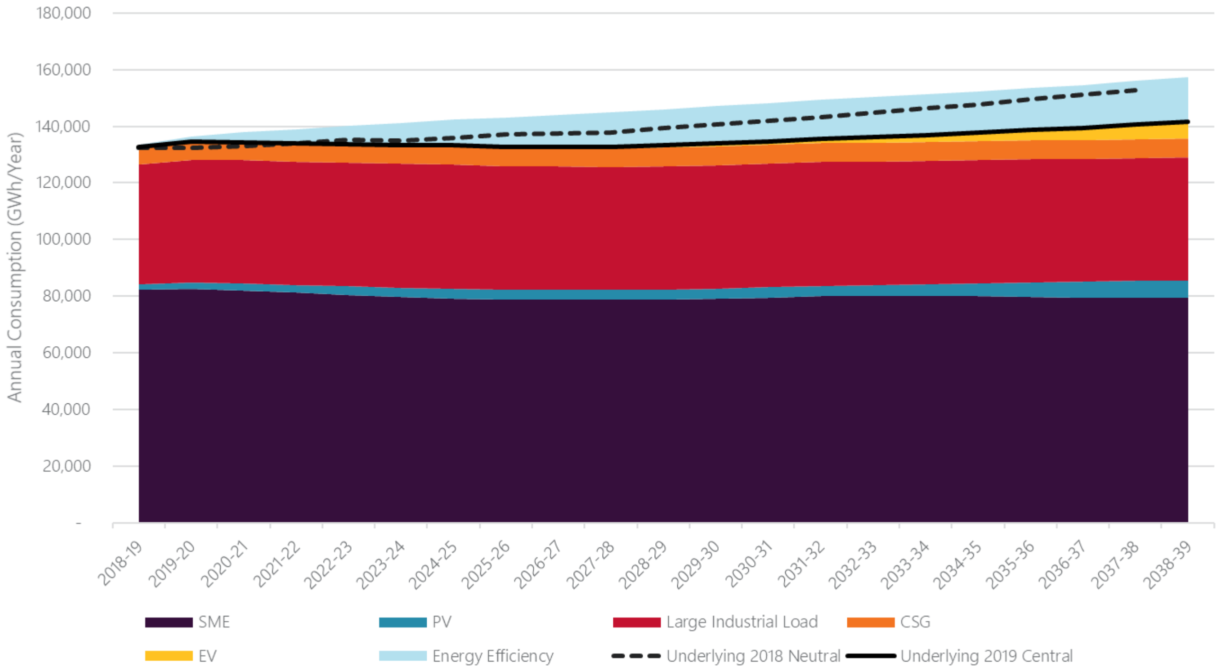


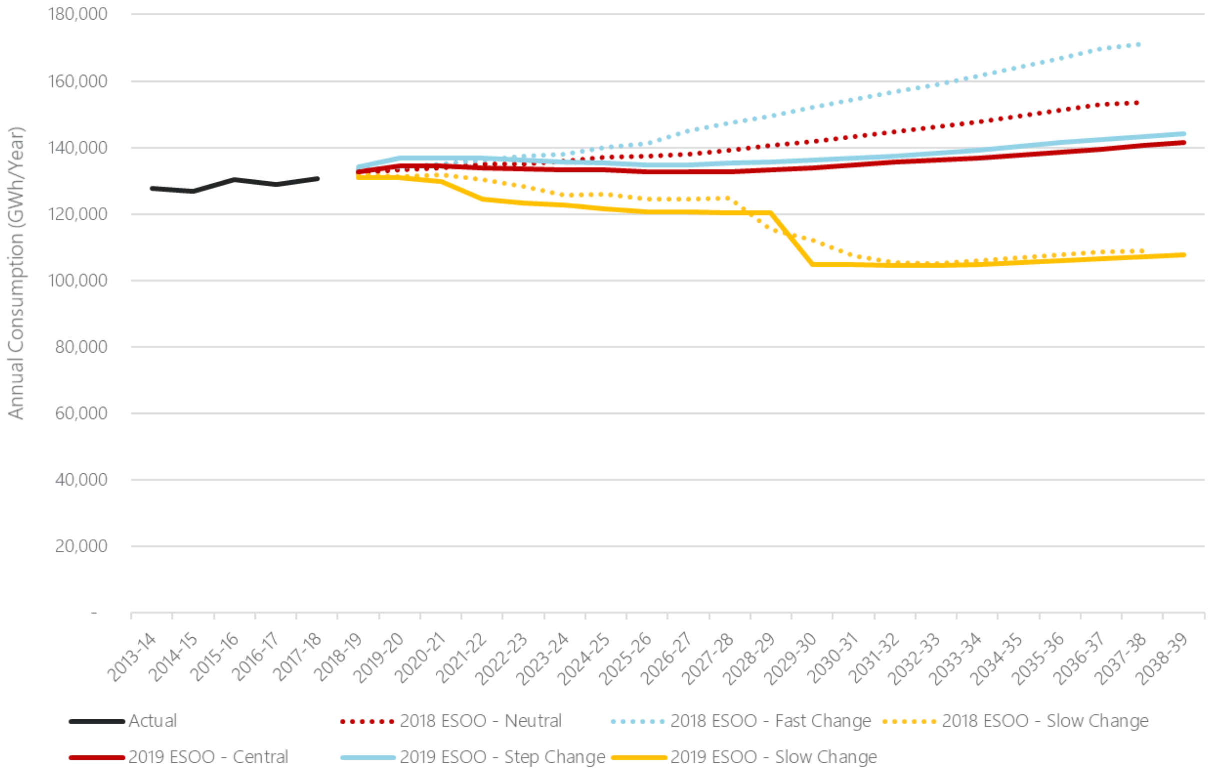
Figure 21 shows the overall trend in forecast business electricity consumption for the three scenarios compared to the 2018 ESOO forecast.

Given different forecast categorisation and model improvements, caution should be taken when comparing current forecasts to the 2018 scenario forecasts.

In the 2019 ESOO Slow Change scenario, there is slightly more downside risk associated with the potential closure of large industrial loads and declining production due to milder economic conditions than forecast last year.

The 2019 Step Change scenario is lower than the 2018 Fast Change scenario over the medium to long term, as lower consumption from energy-intensive industries, higher uptake of small-scale embedded technologies, and stronger EE savings feature in the Step Change scenario narrative and thus the 2019 forecasts.

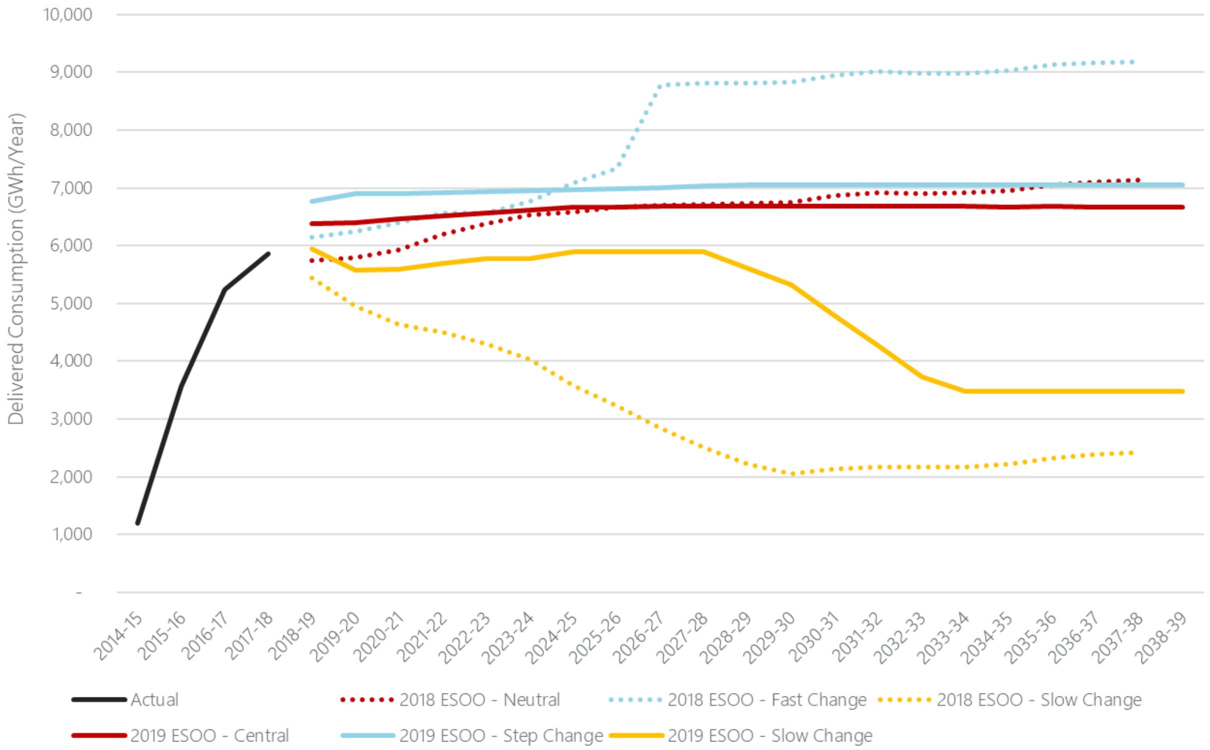
Figure 21 NEM underlying business electricity consumption forecast, all scenarios, 2018-19 to 2038-39 and compared to the 2018 ESOO



Coal seam gas sector forecasts

Electricity forecasts for the CSG sector, shown in Figure 22, reflect the grid-delivered electricity consumed by east coast LNG consortia in the extraction process for CSG production.

Figure 22 NEM delivered CSG electricity consumption forecast, all scenarios, 2018-19 to 2038-39



Electricity consumption forecasts reflect CSG production forecasts provided to AEMO by the LNG consortia, consistent with the 2019 *Gas Statement of Opportunities* (GSOO)[71]. In summary:

- For the Central scenario, electricity consumption is projected to remain relatively stable after initial ramping of CSG production, with some small rises allowing producers to capitalise on spot market opportunities.
- As outlined in the 2019 GSOO, AEMO no longer considers LNG export expansion and development of an additional seventh export train as a reasonable development in any of these scenarios, given alternative international supply opportunities and the relatively high cost of developing only one additional train. This has been removed from the Step Change scenario (the 2018 Fast Change scenario included consumption growth from this assumed development).
- For the 2019 Slow Change scenario, the forecast decline in LNG demand occurs later than was assumed in the 2018 ESOO, where the exploration and development of CSG wells stopped almost immediately. AEMO considers it reasonable to assume that minimum contract levels will be met over the next 8-12 years, regardless of where the gas is sourced. In the longer term, existing wells in this scenario decline to minimum production levels by 2033, equivalent to a minimum capacity of approximately three trains.

Large industrial loads (LIL)

The LIL sub-sector includes the aggregation of the coal mining and manufacturing sub-sectors, as well as other large energy users outside these two sectors:

- Coal mining loads are those mainly engaged in open-cut or underground coal mining.
- Manufacturing loads include those involved in transforming materials, substances, or components into new products. Key industries in this sector include basic chemical manufacturers, primary metal manufacturers, food manufacturers, and metal ore mining.

This change in forecasting approach since the 2018 ESOO better captures the different drivers affecting the forecast.

For the 2019 ESOO, AEMO has conducted detailed interviews and surveys with large industrial electricity users to identify broad market dynamics affecting these loads, as well as industry-specific opportunities and threats. This process revealed that many large industrial consumers are sensitive to electricity prices and face challenging decisions about their ongoing domestic operations. Some users report a more favourable electricity price outlook compared to this time last year, but some uncertainties remain around the long-term sustainability of businesses facing high energy bills. This uncertainty is reflected in the Slow Change scenario.

Survey and interview feedback suggests large users are needing to contract their electricity supply for relatively shorter periods, as favourable long-term contract terms are more difficult to agree to. During interviews with AEMO, large users also outlined several investment decisions in EE programs, technological improvements, automation upgrades, and on-site uptake of renewable generation to provide some of the loads' energy needs[72]. Some businesses continue to be exposed to price pressures, although others are more energy price insensitive and forecast moderate increases to their consumption in the short term.

In the 2019 forecasts:

- In the Central scenario, the forecast trend is for modest increases in electricity consumption for LILs over the 20-year outlook, with an average annual increase of 0.1%. This is primarily due to industry feedback suggesting there is currently little incentive for new major investment.
- The Step Change scenario forecast remains mainly flat over the forecast period, and similar to the Central scenario, again with relatively few significant investments.

[71] AEMO, 2019 GSOO, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[72] On the basis of interviews and surveys conducted.

- Under the Slow Change scenario, consumption is forecast to fall over the short to medium term, with some closures assumed in the forecast. These risks increase over the 20-year outlook, due to persisting weak economic conditions eroding business resilience in this scenario.

Small to medium enterprises (SME)

The majority of businesses in the Australian economy are SMEs. The SME sector includes all businesses which are not included in the CSG and LIL sectors, and consists primarily of businesses in the services sector and smaller manufacturing businesses:

- The services sector is dominated by financial services, transport, retail, education, health care, and telecommunications.
- Smaller manufacturing activities include food processing and the fabrication and repair of metal and other products, machinery, and equipment.

Consumption growth in the SME sector is correlated to broader GSP and population growth.

AEMO has applied a new business sector forecasting methodology, considering the feedback received from AEMO's Demand Forecasting Methodology consultation.[73] The development of a dedicated SME model improves energy forecasts by more appropriately capturing the structural changes taking place in the economy outside of large energy users. Previously, the manufacturing sector was forecast separately, but the historical data reflected consumption by large energy-intensive businesses. These businesses are considered less representative for this sector in the 20-year outlook, as, in general, large-scale industrial production is expected to shrink as a proportion of Australia's economic output, as energy-intensive manufacturing (captured by the LIL sector) continues to be displaced by growth in the services sector.

The 2019 scenarios show:

- In the Central scenario, growth in GSP and population is forecast to be offset by increased energy productivity and EE savings and commercial rooftop PV growth. By 2038-39, total SME delivered consumption is expected to fall by 2 TWh – this includes approximate net effect of offsets for rooftop PV of 6.3 TWh, and EE of 14 TWh.
- In the Step Change scenario, the impacts of higher economic activity, EV uptake, and population growth are projected to be offset by much higher EE measures (and hence higher energy productivity). This results in the 2019 Step Change scenario crossing below the 2019 Central scenario by 2029-30, with EE offsetting consumption by 26 TWh by 2038-39 compared to the 2018-19 base year.
- In the Slow Change scenario, there is greater downside risk for energy consumption, due to milder economic and population growth (that is, reduced business confidence and sluggish export markets). Consumption remains lower than the Central scenario throughout the forecast horizon.

3.2 Maximum demand and minimum demand forecasts

Key insights

- Differences in observed growth rates between mainland regions are generally driven by differences in projected business consumption, PV uptake, and the level of investments in EE in each region.
- The short-term (1-5 years) maximum operational demand (50% POE) forecast indicates:
  - In New South Wales and South Australia, the forecast is expected to remain relatively flat.
  - Queensland is expected to have an average annual growth rate of around 0.6%.
  - Victoria is expected to decline by 0.8%.

[73] AEMO, Demand Forecasting Methodology consultation, at https://www.aemo.com.au/Stakeholder-Consultation/Consultations/National-Electricity-Market-Demand-Forecasting-Methodology-Issues-Paper-Consultation.

- Tasmania is forecast to grow slightly over the next couple of years (0.6% average annual growth rate by 2020-21), due to projected growth in LIL demand.
- In the medium term (5-10 years), the same regional trends continue, apart from in Tasmania, where maximum demand is projected to be flat over this period.
- In the long term (10-20 years), forecasts for maximum operational demand from 2028-29 to 2038-39 are:
  - An average annual growth rate of 0.7% in New South Wales and 0.6% Queensland, due to forecast EV charging at time of maximum demand and growth in residential load (driven by population growth) and growth in business load for Queensland (driven by increasing SME business activity).
  - An average annual growth rate of 0.4% in South Australia and 0.6% in Victoria, due to projected EV charging and growth in business and residential (driven by increasing business activity and population growth), partly offset by increasing energy efficiency measures.
  - Decline by 0.1% average annual growth rate in Tasmania, due to forecast declining business load.
  - Climate change is projected to drive growth in maximum demand by around 20-100 MW in the mainland states over the next 20 years, while in Tasmania, where demand is winter peaking, climate change is forecast to cause demand to fall.
- Maximum operational demand is expected to continue peaking between 16:00 and 19:00 local time in most regions for the next 10 years. After that, it is gradually expected to peak an hour later between 17:00 and 20:00 local time, due to increasing uptake of PV. Tasmania currently peaks in the morning in winter and is expected to continue doing so for the entire 20-year forecast.
- Minimum operational demand forecasts are largely driven by projected growth in rooftop PV and PVNSG capacity:
  - Minimum demand in New South Wales, South Australia, and Victoria is expected to fall over the next five years and remain relatively flat to the early to mid-2030s. Towards the end of the forecast, PV capacity is projected to experience a resurgence, causing minimum demand to further decline.
  - Queensland minimum demand is expected to experience steady decline, while in Tasmania it is expected to remain relatively flat. This is largely due to growth in EV charging at time of minimum demand, offset by the reductions in business consumption forecasts discussed in Section 3.1.1.
- Minimum operational demand is expected to move to a midday trough within the next few years in most regions. South Australia is already experiencing midday troughs. Tasmania is expected to trough overnight for the next 10 years then move to a midday trough.
- Compared to the 2018 ESOO forecasts:
  - Maximum operational demand in New South Wales, South Australia, and Victoria is forecast to be lower over the longer term, deviating from the 2018 ESOO forecast after 2021-22 in Victoria and South Australia, and after 2023-24 in New South Wales. This is due to lower forecast business load driven by changed assumptions for both EE and SME load, as this component is approximately 60-70% of demand between the hours of 16:00 and 19:00 (depending on region).
  - The Queensland starting point is higher than last year, due to the new forecasting model that now better reflects recent demand observations.
  - Tasmania maximum operational demand is slightly higher at the start of the forecast due to an initial step change in LIL, while the forecast trend is roughly the same.
  - Slightly more modest forecasts of rooftop PV and PVNSG in the short to medium term result in slower rates of change in the typical daily load profiles. Maximum operational demand is slower to shift to beyond sunset and daytime minimum operational demand troughs are slower to eventuate than forecast in 2018.

Maximum (and minimum) demand outcomes vary significantly year-on-year, because they are heavily dependent on weather outcomes, in combination with when maximum or minimum demand occurred (which month, weekday versus weekend, and time of day). A single point forecast is therefore not meaningful, and AEMO presents these forecasts as a distribution given by the 10%, 50%, and 90% POE forecasts.

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.

The forecast maximum and minimum demand is influenced by the same drivers as consumption (see Chapter 2), but the forecast trend may differ from that forecast for consumption for the following reasons:

- **Consumption type** – AEMO splits consumption into heating, cooling, and baseload (not temperature sensitive) consumption. Cooling consumption is relatively small on an annual level, but contributes significantly to demand on extreme hot days, which typically drive maximum demand events in the mainland regions. Any underlying drivers that affect cooling, heating, and baseload differently can cause differences in forecast trends between maximum demand and annual consumption. For example, EE directed to lower cooling requirements will affect annual consumption relatively little and summer maximum demand relatively more.
- **Technology uptake** – growth in rooftop PV uptake lowers consumption from the grid (both delivered and operational consumption) substantially by midday and less in the late afternoon, and has no impact after sunset. As more PV capacity gets installed, timing of operational maximum demand has moved to later in the day where it has less impact relative to the impact on annual consumption.

These factors are also resulting in the operational maximum demand becoming 'peakier' relative to consumption. Overall, the load factor (average demand divided by maximum demand) is decreasing over time because annual operational consumption and maximum operational demand are growing at different rates, as shown in Figure 23.

Figure 23 Recent changes to load factor for mainland NEM regions, 2010-11 to 2018-19

In Queensland, for example, the average monthly maxima in the past 12 months are up 3% compared to a year ago, but annual energy is down 0.7%. Discussions with local network companies suggest a driver may be an increase in air-conditioner ownership coupled with consumers changing the way they use cooling, with less tolerance for high temperatures towards the end of summer. Moreover, while rooftop PV uptake continues to have noticeable impacts on operational consumption, the forecast impact on operational maximum demand, which now occurs closer to sunset, is reduced.

The following summarises the forecast maximum demand outlook over the short, medium, and longer term for the Central scenario[74].

Short-term outlook (0-5 years)

Over the next five years, maximum operational demand (50% POE) in:

- New South Wales and South Australia is expected to remain relatively flat. The average annual growth rate in New South Wales and South Australia is within +/-0.3%. Growth in residential load is projected to be offset by slight growth in rooftop PV capacity and a decline in business load due to increasing EE.
- Queensland is expected to grow by around 0.6% average annual growth rate, due to growth in business load and residential load attributed to increasing SME business activity and population growth, slightly offset by growth in rooftop PV capacity.
- Victoria is expected to decline by 0.8% average annual growth rate, driven by a decline in business load due to increasing EE.
- Tasmania is forecast to grow by 0.64% average annual growth rate due to growth in LIL over the next couple of years to 2021. Over the five-year outlook, the average annual growth rate in Tasmania is 0.5%.

As this is relevant for the RRO, peak operational demand on an 'as generated' basis has been presented for the next five years in Table 18 of Chapter 6.

Medium-term outlook (5-10 years)

Between 2023-24 and 2028-29, maximum operational demand (50% POE):

- In New South Wales, South Australia, and Victoria is forecast to remain relatively flat, with an average annual growth rate of +/-0.2%. This is mainly due to projected EE gains reducing total business load, offset by forecast growth in residential loads.
- In Tasmania is forecast to decline slightly by 0.3% average annual growth rate. A large proportion of maximum demand is driven by business load and LIL, which is forecast to decline slightly in this period.
- In Queensland is forecast to continue growing, due to projected growth in residential and business load due to increasing SME business activity and population growth.

Longer-term outlook (10-20 years)

From 2028-29 to 2038-39:

- Some EV charging at time of peak is forecast to drive up maximum demand across the regions. By 2038-39, EV charging is projected to represent 2-6% of maximum demand, depending on the region. As Section 2.2.3 outlined, the number of EVs is forecast to grow substantially, and a proportion of these are projected to charge at time of maximum demand (see Figure 11 in Section 2.2.3).
- Maximum demand (50% POE) in New South Wales and Victoria is forecast to experience slight growth, by 0.7% and 0.6% average annual growth rate respectively. This is due to some EE schemes being expected to taper off, leading to growth in business load and residential load, as well as some EV charging at time of maximum demand (projected to represent 5% and 6% of demand (680 MW-500 MW by 2039) in New

[74] For the forecast outcomes for the Slow Change and Step Change scenarios, see AEMO's data portal at http://forecasting.aemo.com.au.

South Wales and Victoria, respectively, by 2038-39). Continued decline in residential cooling load is projected due to EE, which slightly offsets growth in the other growth drivers.

- Maximum demand in Queensland is forecast to continue growing, by around 0.6% average annual growth rate, due to growth in residential and business load attributed to increasing SME business activity and population growth. This growth is projected to be marginally offset by growth in rooftop PV and PVNSG capacity, as well as EE impacting cooling load. EV charging at time of maximum demand in Queensland is projected to represent around 4% (400 MW) of maximum demand in 2039.
- Maximum demand in South Australia and Tasmania is forecast to remain relatively flat compared to the other regions, with 0.4% and -0.1% average annual growth rate respectively. In Tasmania, forecast declining residential load offsets expected EV charging at time of maximum demand. In South Australia, growth in residential and business baseload, due to population growth and growth in LIL as well as EV charging, is forecast to be offset by lower cooling load driven by EE. EV charging at time of maximum demand is projected to represent around 2% of demand in Tasmania and around 3% of demand in South Australia (20 MW-100 MW by 2039).

Comparison with 2018 ESOO forecast

Forecast maximum demand is higher in the start year for New South Wales and Queensland, as AEMO's new hybrid model better captures changes to historical trends. This also results in a narrower range between the different POE outcomes, as the modelling technique captures changes in variance over time. This has in particular lifted the 50% POE forecast (see Figure 24) in New South Wales and Queensland.

The other regions' starting points are broadly similar in the start year. In general, the starting points of the 10% POE align well across the different regions (see Figure 25), with only Queensland having a significant shift up as the models have been improved to address the underforecasting reported in the Summer 2019 Forecast Accuracy Update[75].

In the short to medium term:

- Forecast growth rates in Queensland and South Australia are similar.
- In New South Wales and Victoria, the projected growth rate is flatter, due to stronger EE forecasts causing slower growth (if not decline) in business load.
- Tasmania maximum operational demand is forecast to be slightly higher at the start of the forecast due to an increase in LIL, then to remain relatively flat, compared to the 2018 ESOO.

In the longer term, forecast maximum demand is generally lower for all regions in this 2019 ESOO. This is predominately due to lower forecast EV uptake and proportionally less charging at time of maximum demand. To a lesser extent, higher forecast EE savings also contribute to reduced demand relative to the 2018 ESOO towards the end of the horizon.

[75] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/2019-Summer-Forecast-Accuracy-update.pdf.

Figure 24 Regional summer (winter for Tasmania) 50% POE maximum operational demand (sent out) comparing 2018 ESOO vs 2019 ESOO

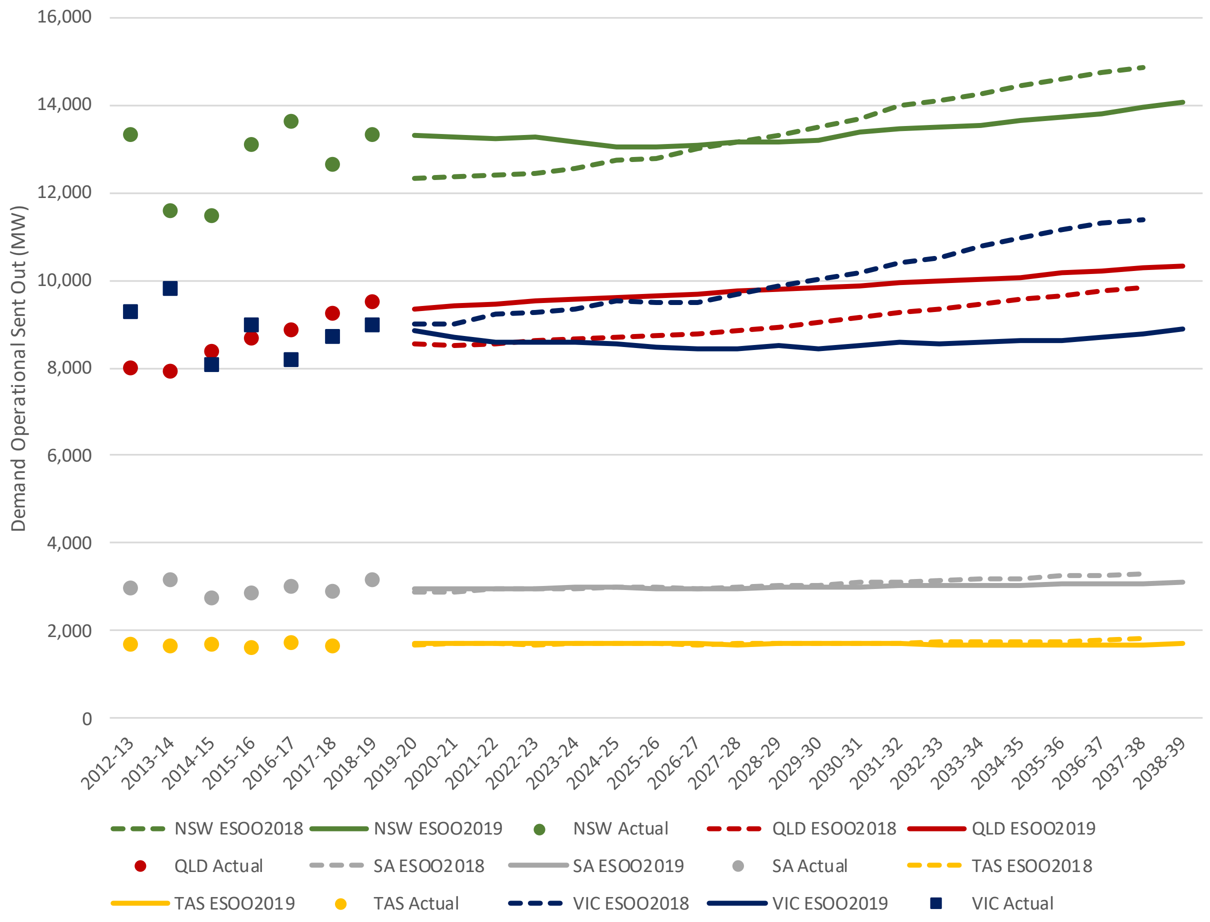
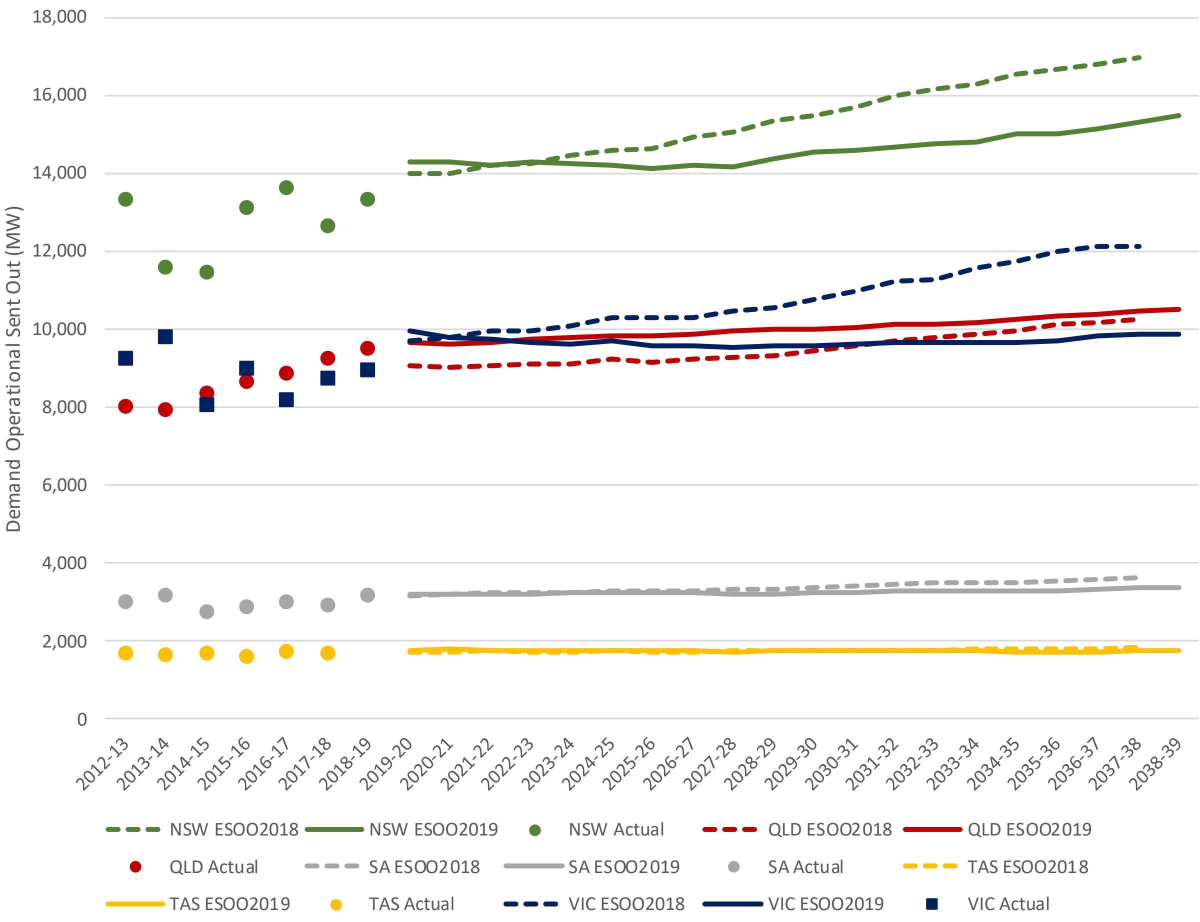


Figure 25 Regional summer (winter for Tasmania) 10% POE maximum operational demand (sent out) comparing 2018 ESOO vs 2019 ESOO



Change in timing of maximum demand

Maximum demand is not forecast to shift later in the day as quickly as projected in the 2018 ESOO, which had most regions approaching sunset peaks within the next five years.

This change is due to lower rooftop PV and PVNSG forecast capacity in the short term in the 2019 ESOO.

Maximum operational demand is now forecast to occur between 16:00 and 19:00 local time in Victoria and New South Wales and between 16:30 and 19:30 local time in South Australia until the early to mid-2030s, then shift later in the day, by an hour. This is due to relatively forecast low PV capacity uptake until the early to mid-2030s.

Higher PV and PVNSG uptake forecasts in Queensland are expected to cause the region to move to a sunset peak by 2028-29, sooner than other regions. In the 2018 ESOO, this shift to sunset was expected by 2025-26.

Tasmania is not projected to see any change in the timing of maximum demand. It currently peaks in the morning in winter, and is expected to do that for the entire 20-year forecast.

Maximum demand distribution

Table 4 shows maximum summer operational demand (sent out) forecasts for 10% POE and 50% POE.

It shows that 10% POE demand events are about 8% higher than 50% POE demand events, although this difference varies 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 are 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.

Forecast maximum operational demand on an as generated basis is provided in Section 6.5, representing the forecast one-in-two year peak demand forecast under the RRO rules.

Table 4 Forecast summer maximum operational demand (sent out) by region, Central 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
2019-20	14,293	13,291	9,643	9,355	3,193	2,950	1,431	1,370	9,967	8,837
2023-24	14,231	13,146	9,796	9,572	3,224	2,992	1,436	1,376	9,600	8,574
2028-29	14,368	13,169	9,987	9,799	3,224	2,994	1,416	1,355	9,589	8,504
2038-39	15,478	14,078	10,498	10,335	3,361	3,102	1,414	1,356	9,893	8,889

Table 5 shows the maximum winter demand (sent out) for the same POEs. Years here refer to calendar years. Tasmania has its annual peak in winter, driven by heating load.

Table 5 Forecast winter maximum operational demand (sent out) by region, Central 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
2020	12,185	11,684	8,153	7,789	2,452	2,350	1,774	1,720	7,799	7,224
2024	11,919	11,409	8,440	8,058	2,464	2,357	1,777	1,728	7,660	7,100
2029	11,928	11,444	8,722	8,349	2,498	2,396	1,747	1,701	7,717	7,135
2039	12,783	12,350	9,254	8,881	2,604	2,507	1,744	1,697	8,302	7,769

3.2.1 Minimum demand

Minimum demand is forecast to decline over the next 3-5 years out to 2024-25 in New South Wales, Victoria, South Australia, and Queensland.

It is also forecast to approach the middle of the day within the next couple of years, in all regions except Tasmania, due to projected increases in rooftop PV and PVNSG capacity. Tasmania has a relatively larger proportion of business load compared to the other regions, so minimum demand typically occurs overnight or after sunset. Tasmania is expected to approach the middle of the day over the next 15 years. South Australia already experiences its trough in the middle of day.

Compared to the 2018 ESOO, minimum demand is not forecast to decline as quickly, mainly due to lower forecasts of rooftop PV and PVNSG capacity. As a result, minimum demand in South Australia is now not forecast to approach zero in the Central scenario. In the higher DER uptake scenario (Step Change), minimum demand (90% POE) is forecast to reach zero in 2024-25 in South Australia and in 2031-32 in Victoria.

In the long term, forecast minimum demand in Queensland continues to decline, due to continual projected growth in rooftop PV and PVNSG capacity. In Victoria, rooftop PV capacity is forecast to experience a resurgence after 2032-33 as uptake accelerates again, which causes projected minimum demand to fall further. In New South Wales, South Australia, and Tasmania, forecast minimum demand remains relatively flat.

Minimum demand distribution

Table 6 shows minimum operational demand (sent out) forecasts for 90% POE and 50% POE. For the first time, AEMO forecasts of minimum operational demand have considered the shoulder seasons (spring and autumn) where demand tends to be lower but rooftop PV and PVNSG is relatively high. It shows that 90% POE demand events are between 3% and 5% lower than 50% POE demand events, although this difference varies depending on the region.

Table 6 Forecast minimum operational demand (shoulder) by region, Central scenario (MW)

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020	5,405	5,213	4,150	3,913	568	511	885	834	3,047	2,803
2024	4,762	4,511	3,512	3,310	452	393	892	840	2,423	2,201
2029	4,609	4,347	3,240	3,021	472	414	874	823	2,276	2,044
2039	4,306	3,998	2,378	2,124	425	361	869	814	1,556	1,314

Summer and winter minimum operational demand (sent out) forecasts are presented in Table 7 and Table 8 respectively.

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

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020	5,369	5,192	4,434	4,222	598	542	897	810	3,071	2,864
2024	5,093	4,901	3,902	3,621	504	451	902	813	2,452	2,249
2029	5,008	4,784	3,682	3,382	526	473	884	794	2,282	2,077
2039	4,983	4,701	3,029	2,610	494	443	863	765	1,601	1,358

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

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020	5,918	5,615	4,247	4,049	665	575	1,020	975	3,136	2,909
2024	5,284	4,965	3,768	3,553	644	549	1,023	978	2,755	2,502
2029	5,276	4,957	3,528	3,307	688	584	1,009	965	2,731	2,455
2039	5,242	4,890	2,742	2,484	657	551	1,002	957	2,339	1,965

3.3 Demand side participation forecast

For the 2019 ESOO, AEMO has updated its estimate of DSP responding to price and reliability signals. The estimates are based on information provided to AEMO by all registered market participants regarding the DSP portfolios as of April 2019, as described in AEMO's DSP forecasting methodology paper[76].

Table 9 and Table 10 show estimated DSP for the coming summer 2019-20 and winter 2020. From July 2020, DSP in Victoria is forecast to reduce by 100 MW because a major load (included in the LIL forecast discussed in Section 3.1) is projected to cease consumption (and therefore cannot provide DSP) from that month.

'Reliability response' in these tables refers to situations where an actual Lack of Reserve notice (LOR 2 or LOR 3) is issued (see NER 4.8.4 for definitions).

Table 9 Estimated DSP responding to price or reliability signals, summer 2019-20

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	42	6	4	0	14
> $500/MWh	78	11	11	1	46
> $1000/MWh	80	12	12	30	50
> $2500/MWh	86	25	19	30	58
> $5000/MWh	93	32	27	30	60
> $7500/MWh	93	32	33	30	60
Reliability response	93	52	33	30	185

Table 10 Estimated DSP responding to price or reliability signals, winter 2020

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	42	6	4	0	14
> $500/MWh	78	11	11	1	46
> $1000/MWh	80	12	12	30	50
> $2500/MWh	86	25	19	30	58
> $5000/MWh	93	32	27	30	60
> $7500/MWh	93	32	33	30	60
Reliability response	93	32	33	30	160

[76] At https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

4. Supply forecasts

This chapter outlines:

- The expected development of generation and battery storage in the 10-year outlook.
- The assumptions that underpinned AEMO's modelling of dispatchable and variable renewable generation.
- The approach AEMO took to modelling the existing transmission network and committed and proposed network augmentations.

Key insights

- The reliability of some dispatchable generating plant, particularly in Victoria, has continued to remain at lower levels compared to long-term averages, reflecting the aging of the generation fleet.
- The 2018-19 summer was characterised by a number of critical plant outages during periods of peak demand. Since summer, there have been two well-publicised, long-term outages at power stations in Victoria that have resulted in over 750 MW of capacity being unavailable until at least mid-December 2019, with some prospect that these outages could continue into the key summer months where maximum demand typically occurs and the risk of USE is highest.
- Meanwhile, the development of new wind and solar generation across the NEM has continued to be strong, with over 2,800 MW of capacity installed since the 2018 ESOO. In addition, 86 MW of utility-scale battery storage projects have been built in this period across Victoria and South Australia.
- As of 18 July 2019, over 7.2 GW of new capacity is committed to enter the market, with the majority being wind and solar generation:
  - There is 4.7 GW of wind and solar expected to reach full commercial use date before 2021-22, and over 41 GW of proposed wind and solar projects are known to AEMO.
  - The Snowy 2.0 project (2,040 MW) is assumed to be fully operational from March 2025.
  - Barker Inlet Power Station (210 MW) is expected to commence full commercial operation in the coming months to offset the mothballing of Torrens Island A Power Station (480 MW progressively over the next two years).
- There remains strong interest in new dispatchable generation, with over 11.5 GW of hydro, gas, and battery storage capacity proposed, but not yet committed.
- In addition to the mothballing of Torrens Island A, Liddell Power Station (1,800 MW) and Osborne Power Station (172 MW) are also expected to close by the end of 2023.

4.1 Generation changes in the ESOO

The ESOO includes only existing and new generation and battery storage projects that meet AEMO's commitment criteria, as published in the Generation Information update on 18 July 2019. The data published in that update reflects information provided to AEMO by participants up to 1 July 2019, and includes the information required under the three-year notice of closure rule. Precise closure dates have not been provided to AEMO beyond the three-year period.

The 2019 ESOO includes projects classified in the Generation Information update as either:

- Committed[77], or
- Under construction and well advanced in becoming committed (Committed*)[78].

The Committed projects become operational on dates provided to AEMO, while advanced projects that are under construction are assumed to commence operation after the end of the next financial year (1 July 2021), to reflect greater uncertainty in commissioning. For further details please refer to the Reliability Forecasting Methodology Final Report[79].

In total, the 2019 ESOO includes over 7,200 MW of new generation and storage capacity (of which 289 MW is classified as Committed*), as well as capacity upgrades to existing generators. Over 4,400 MW of this capacity, including Snowy 2.0, is in addition to what was considered as committed or upgraded in the 2018 ESOO.

For the purposes of this report, any future reference to committed projects includes those projects that are advanced and under construction.

Table 11 summarises committed generation developments, augmentations, retirements, and withdrawals announced within the next 10 years and included in this 2019 ESOO. The references are to generation changes listed after the table.

Table 11 Generation capacity developments assumed in the 2019 ESOO (nameplate capacity, MW)

Generation type	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM
Wind	496	-	1,678	86	265	2,526
Solar	613	1,171	325	135	-	2,244
Water	-	2,040 [i]	-	-	-	2,040
Gas-powered generation (GPG)	-	-	-	210 [ii]	-	210
Generator upgrades	-	100	135	24	-	195
Battery storage	-	-	20	10	-	30
Withdrawals/ retirements	419 [D,E]	1,800 [B]	-	660 [A,C]	208 [F]	3,087

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

A. Torrens A Power Station (480 MW, South Australia) will be mothballed, with two units reducing their capacity to 0 MW in late 2019 following the commissioning of Barker Inlet Power Station (unless

77 Committed projects meet all five of AEMO's commitment criteria (relating to site, components, planning, finance, and date). For details, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

78 In AEMO's Generation Information page, committed* or Com* projects are projects that are classified as Advanced and have commenced construction or installation. Advanced projects meet AEMO's site, finance, and date criteria but are required to meet only one of the components or planning criteria.

79 See Section 5.3 at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Forecasting-Methodology-Final-Report.pdf.

permission to continue operating is granted by the South Australian Government), and the other two units ceasing operation in 2020 and 2021.

B. Liddell Power Station (1,800 MW summer capacity, New South Wales) will retire one unit in April 2022 and the remaining three units in April 2023.

C. Osborne Power Station (172 MW summer capacity, South Australia) has indicated an expected closure date of 1 January 2024.

D. Swanbank E (350 MW summer capacity, Queensland) has indicated an expected closure date of 1 January 2029.

E. Mackay Gas Turbine (34 MW, Queensland) has indicated an expected closure date of 1 January 2022.

F. Tamar Valley combined-cycle gas turbine (CCGT) (208 MW, Tasmania) is not in regular service, and is currently 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. It was last in service in summer 2018-19.

Major new dispatchable entrants are:

i. The Snowy 2.0 project (2,040 MW summer capacity New South Wales), which is assumed to be fully operational from March 2025.

ii. Barker Inlet Power station (210 MW summer capacity South Australia), which is assumed to be fully operational from November 2019, and partially offsets the withdrawal of Torrens A Power Station.

Region-specific supply information is provided in Appendix A2.

4.2 Generation availability

4.2.1 Dispatchable generation

AEMO models the capabilities of dispatchable generation capacity by applying inputs sourced from market participants. The maximum seasonal 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 10% POE maximum demand in each region, and reflect the capability of the generator assuming no reductions due to unplanned outages or maintenance.

AEMO separately collects information from all generators via an annual survey process on the timing, duration, and severity of historical unplanned forced outages. This data is used to calculate the probability of full and partial forced outages for each financial year. Analysis of this historical outage data has affirmed that some categories of plant have seen a deterioration compared with the longer-term historical performance. This is reflected in 2019 ESOO modelling by using the four most recent years of plant performance. No further deterioration has been applied over the duration of the ESOO modelling horizon.

Figure 26 below shows the historical full forced outage rate outcomes. The bars show a comparison of rates for AEMO's entire historical dataset (July 2010 to March 2019) and the average of the previous four years. The markers on the chart show the single year outage rates.

The biggest discrepancy between the long-term outage rates and performance in recent years is for brown coal, where recent forced outage rates sit well above the long-term average. There is approximately a 2.5% increase in the full forced outage rate of brown coal using the last four years' average compared to the nine-year average. The last two years have had the highest rates recorded, and all of the last four years' rates have been above the long-term average. The outage rates calculated do not include a number of major outages which were not designated as unplanned forced outages, and the rates do not include the impact of current major generation outages such as the outage at Loy Yang A Power Station.

All other technology aggregations have rates in the past four years which have been both above and below long-term and short-term averages, with a relatively small discrepancy between the long-term average and the average over the most recent four years.

Figure 26 also shows the level of variability in generator reliability from year to year, even when aggregated over many stations. The approach used in this ESOO samples discretely from the annual performance of each station, to better capture the observed variability in generator performance.

Figure 26 Historical full forced outage rate comparison

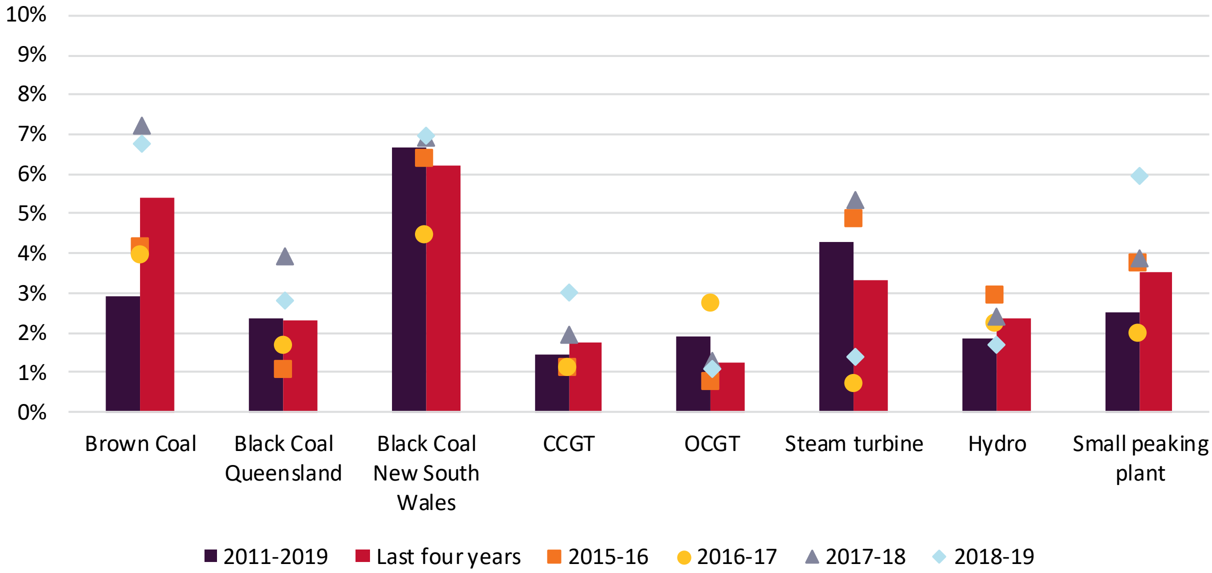
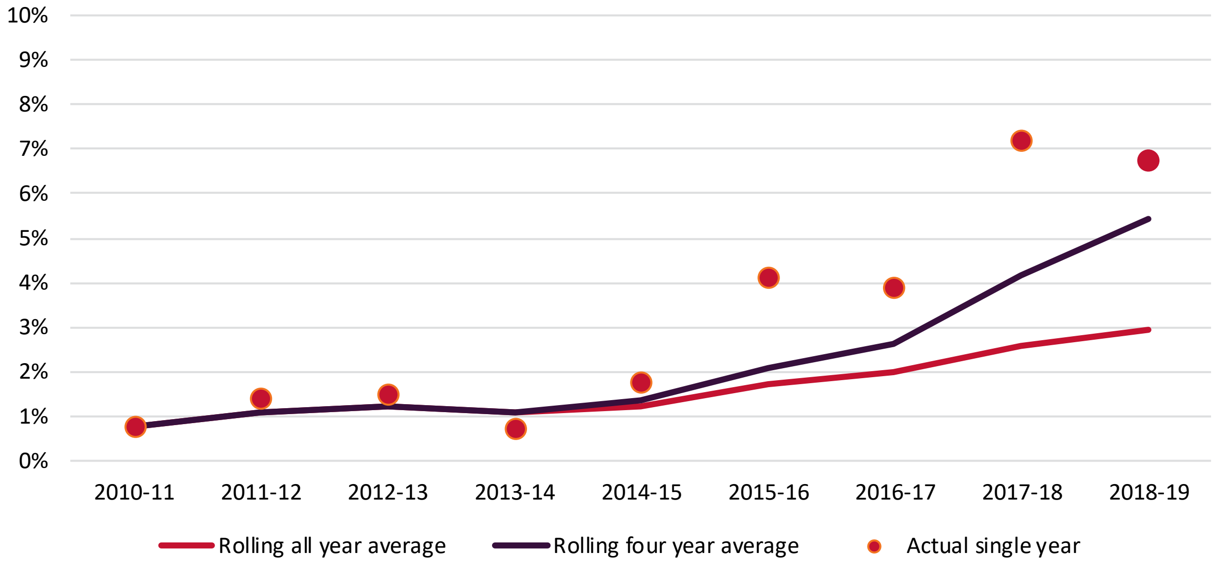


Figure 27 below shows the historical full forced outage rates of brown coal plant in Victoria, showing an upward trend in forced outage rates in 2015-16 that continues to the most recent year in 2018-19.

Figure 27 Historical brown coal full forced outage performance



This clearly shows that an approach which uses the most recent four years of outage data to estimate performance would have been more accurate than using the long-term average. Even if the approach of weighting towards recent outcomes had been applied to calculate forced outage rates in all previous ESOOs, the actual reliability of brown coal would still have been worse than the forecast rate in each of the previous five financial years.

The key changes implemented for modelling generation outage rates in the 2019 ESOO were that AEMO:

- Used station-level data for thermal generators (except small peaking plant with units smaller than 150 MW, where aggregation continues to be used due to the small sample size on which to assess the performance of these units).
- Provided power station owners the opportunity to review outage rates assumed and provide feedback.
- Applied four sets of outage parameters (from each of the previous four years of data provided) in the model, such that they were equally weighted.

In two cases, power station owners provided feedback on exceptional outages that occurred in one of the historical years sampled, along with justification why those outages would be inappropriate to apply in the calculation of future forced outage rates. In both cases, AEMO accepted this evidence and adjusted the calculation of historical outage rates accordingly. The outage rates influenced by the exceptional outages were removed and replaced by the average outage probabilities from the other three years.

Table 12 shows the aggregated outage assumptions used in the 2019 ESOO, including a comparison of the full forced outage rate against the 2018 ESOO assumptions. AEMO publishes outage parameters for a number of technology aggregations to protect the confidentiality of this data.

Table 12 Forced outage assumptions (2019 ESOO)

Generator aggregation	Full outage rate – 2019 ESOO	Full outage rate – 2018 ESOO	Partial outage rate	Partial derating	MTTR[A] – Full outage (hours)	MTTR – Partial outage (hours)
Brown coal	5.43%	5.34%	11.65%	19.09%	47	6
Black coal QLD	2.30%	2.42%	13.12%	17.59%	56	17
Black coal NSW – pre-2022	6.22%	6.56%	26.06%	19.83%	137	20
Black coal NSW – after 2022	4.30%	3.88%	23.84%	17.51%	104	17
CCGT	1.73%	1.33%	0.19%	36.25%	23	29
OCGT	1.26%	3.56%	0.35%	11.96%	7	40
Small peaking plant	3.52%	3.56%	0.39%	7.18%	16	35
Steam Turbine	3.30%	4.58%	0.01%	12.58%	89	64
Hydro	2.34%	1.58%	0.39%	35.74%	17	5

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

4.2.2 Variable renewable generation

The 2019 ESOO modelled variable renewable generation by considering nine historical reference years, which reflect the weather conditions that drove demand and wind and solar production between 2010-11 and 2018-19[80]. This approach preserves any correlation between variable renewable generation and demand, and between variable renewable generators in different locations.

[80] The 2018 ESOO modelled eight reference years: 2010-11 to 2017-18.

Where possible, AEMO used actual generation performance from a generation site, or a site 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 2019 ESOO incorporated wind production data developed by DNV-GL for the assessment of renewable energy zones (REZs) in the 2018 ISP.

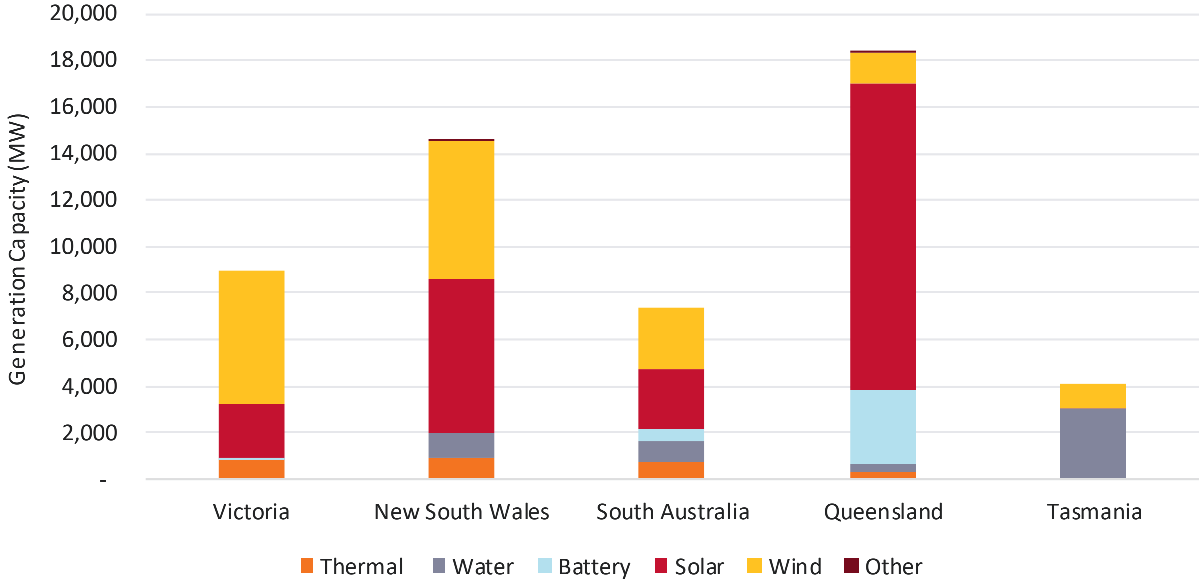
4.3 Pipeline of future projects

There is a substantial pipeline of future projects not yet committed but in various stages of development, from publicly announced to advanced stages of planning. The future projects are spread across all regions, with Queensland having the most in terms of capacity.

With retirement of existing plant, additional energy resource projects will be needed to reduce the risk of USE in the NEM. Over 75% of future projects currently tracked by AEMO are variable generation (solar and wind), and over 5% are battery storage. The remaining 20% of the proposed capacity is hydro and thermal capacity, with the largest component of this being additional hydro generation in Tasmania.

Figure 28 shows the pipeline of projects by region and type of generation, beyond the already committed projects.

Figure 28 Proposed projects by type of generation and NEM region, beyond those already committed



4.4 Transmission modelling

4.4.1 Existing transmission limitations

While several transmission augmentations are currently progressing through the regulatory investment test for transmission (RIT-T) process, no interconnector augmentations are currently committed. The base ESOO scenario therefore only uses existing transmission limits and interconnector capacities, assuming interconnector limits currently in effect continue to apply.

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.

A number of minor augmentations have become committed and were therefore included through their impact on the transmission constraint equations. These augmentations are:

- Red Cliffs to Buronga line uprating, which applies from the 2020-21 summer onwards.
- Gin Gin substation rebuild by December 2020.
- Installation of synchronous condensers in South Australia by January 2021.
- Installation of capacitors at the Armidale substation by March 2021.

4.4.2 Transmission outages

The 2019 ESOO includes the impact of a number of key unplanned transmission line outages or deratings which affect inter-regional transfer capability (see Table 13). AEMO assessed the probability of these outages using historical outage data since 2007, updating the assumptions applied in the 2018 ESOO by considering the past 12 months.

AEMO has applied transmission outages to the same key flowpaths that were chosen in the 2018 ESOO:

- 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. Following this event, Basslink has been operating at a 478 MW limit in both directions and is assumed to continue doing so in this 2019 ESOO, based on forward-looking transfer capabilities in the Medium-term Projected Assessment of System Adequacy (MT PASA). 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.

Table 13 Transmission outage rates

Transmission flowpath	Unplanned outage rate (%)
Dederang – South Morang	0.29
Heywood – South East (Heywood interconnector)	0.13
Basslink	0.08

4.4.3 Future transmission augmentations

As a sensitivity, AEMO has considered the potential impact that the interconnector augmentations identified as Group 1 projects in the 2018 ISP could have on reliability in the NEM over the next five years. These augmentations are summarised in Table 14.

Table 14 ISP Group 1 transmission augmentations modelled

Network upgrade	Details	Assumed timing
Minor QNI upgrade	Increase transfer capacity between Queensland and New South Wales.	September 2022
Minor VNI upgrade	Increase transfer capacity between Victoria and New South Wales.	September 2022

5. Risks in Victoria this summer

This chapter discusses in more detail the projected reliability risks in Victoria this summer.

On 24 and 25 January 2019, the equivalent of approximately 375,000 households[81] were without power for an hour in Victoria and South Australia, due to a combination of factors including extreme temperatures causing high demands and significant levels of unavailable thermal capacity. This load shedding was despite the activation of all available RERT resources that were procured last summer.

The reliability of the aging brown coal generation fleet in Victoria continues its recent trend of poor performance. Furthermore, there are currently two major units in Victoria (Mortlake Unit 2 and Loy Yang Unit 2), which provide over 750 MW of capacity, which are unavailable due to long-term outages and are not scheduled to return until mid-December 2019.

The 2019 ESOO forecasts that the risk of load shedding in Victoria in 2019-20 is high, with the expected level of USE in excess of both the reliability standard and the level of load shedding that was experienced last summer.

The forecast USE in 2019-20 is informed by past experience which suggests there is some likelihood that at least one of the unavailable units (Mortlake Unit 2 and Loy Yang Unit 2) will have a delayed return to service, meaning the plant could be unavailable in key summer months.

Figure 29 below shows expected USE outcomes in Victoria for 2019-20 based on four different sensitivities:

- Both Mortlake Unit 2 and Loy Yang Unit 2 returning to service by mid-December 2019.
- Neither Mortlake Unit 2 nor Loy Yang Unit 2 returned to service until the beginning of March 2020.
- Mortlake Unit 2 in service by mid-December and Loy Yang Unit 2 not in service over summer.
- Loy Yang Unit 2 in service by mid-December and Mortlake Unit 2 not in service over summer.

The modelling projects that, should both units experience delays that result in their capacity being unavailable during key summer months, then the expected level of USE would be dramatically in excess of the current reliability standard, at 0.0047%.

Based on operational experience and an analysis of the historical delay in return to service of units following prolonged outages, the modelling assumes:

- A 30% probability that Loy Yang A Unit 2 is remains out of service until 1 March 2020.
- A 60% probability that the Mortlake unit remains out of service until 1 March 2020.

Based on these probabilities of delayed return to service, the expected USE would be above the reliability standard at 0.0026% in Victoria.

[81] In reality, the load shedding included reductions in consumption from industrial facilities and involved the use of rotational load shedding such that the number of households affected and the duration of time without power would be different from this equivalent number.

Applying the same probabilities of delay, the likelihood that Victoria would exceed the reliability standard would be approximately 22%, as shown in Figure 30. This figure also shows the likelihood of levels of USE that are well in excess of the reliability standard, with a non-trivial (almost 10%) likelihood that USE could be in excess of five times the current standard.

Figure 29 Forecast USE outcomes, Central scenario – 2019-20 sensitivities

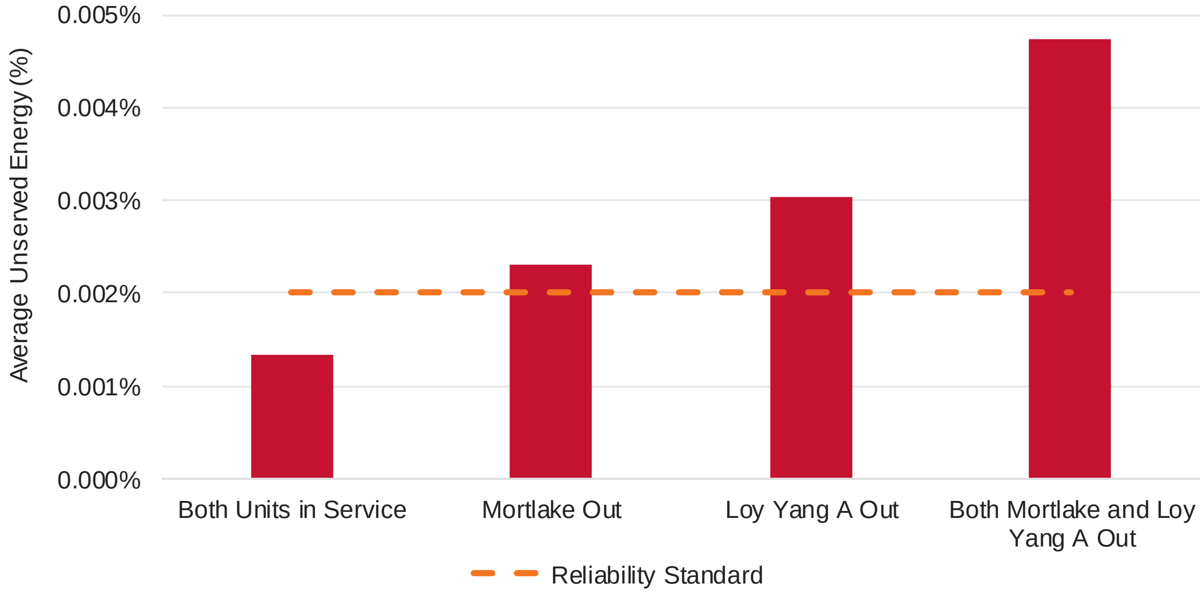
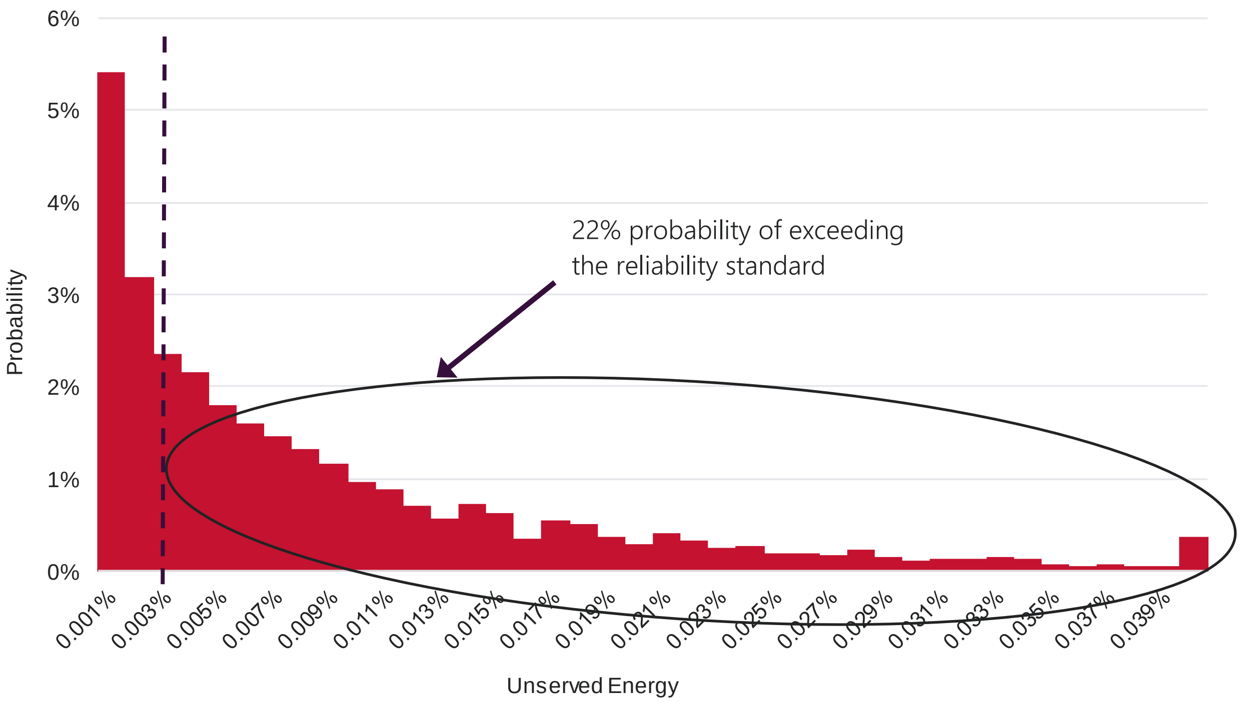


Figure 30 Range of USE outcomes, Central scenario – Victoria 2019-20*



* Only samples with USE are included in this figure. There is a 69.6% likelihood of no USE occurring.

Should the situation arise where neither of the two units returns for the key summer months, the expected probability of not meeting the standard rises to over 29%, with the expected level of USE increasing to 0.0047%.

If Victoria were to experience another extreme heatwave that drove one-in-10 year peak demand, the expected USE would rise to an unprecedented 0.0148%, over seven times the current reliability standard. To manage an event like this, AEMO would be required to load shed the equivalent of between 260,000 and 1.3 million households in Victoria for four hours, typically during extreme temperatures or heatwaves.

Based on the relative probabilities of delays, approximately 125 MW of additional firm capacity would be required to reduce the expected level of USE to the current reliability standard.

Even if 125 MW was procured, should neither unit return to service, the expected level of USE would still be well above the standard at 0.0038%.

Table 15 summarises the risks this summer under the various combinations of recommissioning timings assessed. It also shows (in red) the probability of each scenario combination occurring, based on the assumed probabilities of outage extensions.

It highlights that the reliability standard is only projected to be met in the case where both units return to service on schedule by end of December (expected USE in this case is 0.0013%). The operational challenge is that by the time AEMO has any certainty around the prospect of outage extensions, it may be too late to mobilise additional reserve to help mitigate the supply scarcity risks.

Table 15 Combination of potential outcomes in Victoria, summer 2019-20

	Loy Yang A2 out (30% probability)	Loy Yang A2 in (70% probability)
Mortlake out (60% probability)	• 0.0047% expected USE • 260,000 to 1.3m households without power for four hours • 460 MW reliability gap 18%	• 0.0023% expected USE • 155,000 to 720,000 households without power for four hours • 70 MW reliability gap 42%
Mortlake in (40% probability)	• 0.0030% expected USE • 195,000 to 910,000 households without power for four hours • 215 MW reliability gap 12%	• 0.0013% expected USE • 90,000 to 445,000 households without power for four hours • No reliability gap 28%

Note: When USE is greater than zero but less than the reliability standard of 0.002% USE, the reliability standard is met, but load shedding is still expected to occur.

Actions to help mitigate these risks this summer

AEMO will also work with industry participants and government agencies ahead of the upcoming summer to ensure risks of USE are understood and mitigated where required. This includes information-sharing, contingency planning, and coordination of any planned outages to ensure these are taken during low risk periods where possible.

AEMO is also working with the Victorian Government to secure the maximum permissible reserves via RERT, to ensure Victoria's reliability of supply meets the reliability standard this summer.

Impact of increasing availability at Torrens Island Power Station

Early action is also being taken by industry to help improve Victoria's reliability outlook this summer. On 2 August 2019, AGL announced[82] that it would delay mothballing two units of Torrens Island A Power Station (2 x 120 MW) until March 2020, and was seeking permission from the South Australian Government to operate these two units over summer. AGL had previously indicated that these two units would be withdrawn in late 2019 to coincide with the commissioning of Barker Inlet Power Station (210 MW) in South Australia.

[82] See: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa

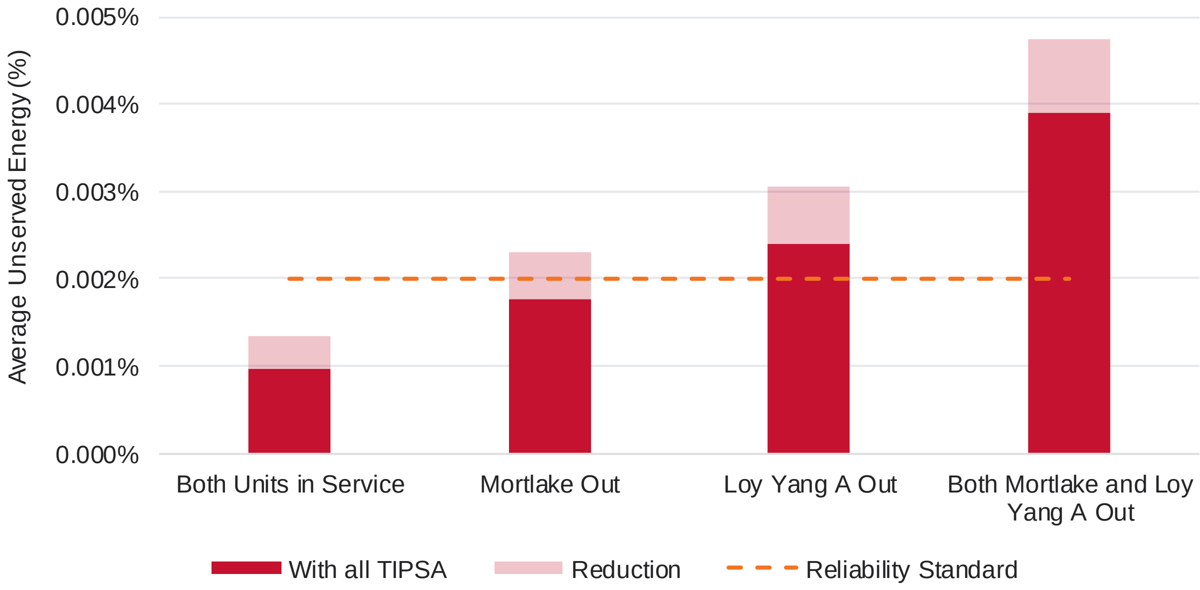
Should permission be granted by South Australian Government, the additional 240 MW capacity available in South Australia would reduce USE risks in South Australia and would also help to support Victoria through the summer, provided there is sufficient interconnector capacity available to import supply from South Australia.

Because the regions have generally correlated peak demands, there are often times when both regions have tight supply-demand balance. This means the ability to transfer power from South Australia to Victoria is relatively infrequently limited by transmission congestion during USE periods in Victoria (the following section provided more commentary on the conditions prevailing during USE periods in Victoria in the simulations).

If these two units of Torrens Island A were made available in addition to the entry of Barker Inlet Power Station, the expected USE in Victoria, weighted across the four sensitivities, would fall to 0.00201%. The expected USE in South Australia would fall from 0.00016% to 0.00003%, a negligible risk.

Although the expected USE falls from being well above the standard to being close to the standard in Victoria, the risk that USE would exceed 0.002% in Victoria remains elevated (19% probability, compared to 22% where Torrens Island A is not fully available).

Figure 31 Impact of Torrens Island A on reliability in Victoria in 2019-20



What factors create the greatest USE risks?

In the 2019 ESOO, AEMO has improved its capability to analyse the conditions that lead to USE events, by investigating the large amounts of data produced during the simulations.

In general, in the market simulations, a number of the following conditions will occur concurrently during periods where load is being shed:

- High demands, generally due to high temperatures and possibly high humidity.
- Below average levels of availability from thermal capacity due to generator outages.
- Lower than average output from variable renewable generation.
- Limited capability to import from South Australia, due to a combination of the above factors also applying in that region.
- Limited import capability from New South Wales, due to generation in northern Victoria, particularly Murray Power Station, and the impact of transmission constraints which are often reduced due to high temperatures.
- Limitations on interconnector flows due to outages, for example, of Basslink.

The box below summarises the findings of the analysis highlighting the main causes of USE in Victoria, based on the 2019-20 forecast.

USE in Victoria – a snapshot view of 2019-20

Based on the forecast for 2019-20, the following conditions characterise the period of USE observed in the simulations (assuming both Mortlake and Loy Yang units return to service in December 2019):

- **Demand** – the majority of USE observations occur when demand is within 5% of the forecast 10% POE peak demand.
- **Thermal capacity** – generally in Victoria, most plant unavailability will be from brown coal, because the gas and hydro units have typically been relatively reliable. Approximately 80% of the USE events occur when the equivalent of at least one brown coal unit is unavailable, and the average level of unavailability during USE periods is roughly equivalent to two brown coal units being unavailable.
- **Variable renewable generation** – the risk of load shedding in Victoria is higher during periods of low wind and solar production. In periods of USE, wind is operating (on average) at approximately 16% of its installed capacity, and large-scale solar at 30%.
- **Import from South Australia** – hot summer temperatures are often correlated between Victoria and South Australia, so when Victoria is under stress due to peak demands, South Australia is also typically experiencing high demands. Furthermore, production from wind generation is also loosely correlated between the two regions. On average, the import Victoria receives from South Australia during USE periods is relatively limited, equivalent to around 125 MW. This is generally not due to transmission limitations, but rather a lack of surplus supply in South Australia. In over 80% of the periods of Victorian load shedding, South Australia is using all available supply resources to support itself and where possible, Victoria, and in 12% of these periods is experiencing USE itself.
- **Import from Tasmania** – Victoria is importing the maximum level of energy from Tasmania in all periods, except in the very rare circumstances where the ability to import from Tasmania is limited due to an outage of key infrastructure such as the Basslink undersea cable.
- **Import from New South Wales** – imports from New South Wales are primarily restricted due to transmission limitations. In general, periods of tight supply-demand balance are not as strongly correlated between New South Wales and Victoria. As a result, New South Wales frequently has ample surplus capacity (on average 1 GW) at times of Victorian load shedding, but is limited in its capability to export by transmission constraints between the Murray Power Station in the Snowy Mountains and Melbourne. In essence, hydro generation in Northern Victoria shares transmission capacity with imports from New South Wales. Given that hydro generation will generally maximise generation during high demand periods, the level of import from New South Wales is typically low, averaging only 145 MW across Victorian USE periods. The transmission capability is most frequently limited by constraints between Dederang (in Northern Victoria) and South Morang (in Melbourne). This line is derated at times of high temperature, and its capacity can be heavily reduced if bushfires are present around the transmission line, which traverses bushfire-prone areas of regional Victoria. Other than the constraints impacting this flowpath, the impact of transmission congestion on generation, and thus reliability, in Victoria is minimal under system normal conditions.

6. RRO reliability forecasts

This chapter meets AEMO's obligations under Section 4A.B.1 of the Market Rules related to the publishing of a reliability forecast and an indicative reliability forecast. This chapter provides the details required under 4A.B.2, including AEMO's forecast of expected USE and whether there is a forecast reliability gap. Supporting materials are on AEMO's website.

Key insights

- Without a T-3 reliability instrument for the same period, a T-1 reliability instrument cannot be requested. As this is the first year the RRO is in effect, there are no T-3 reliability instruments in existence. There are also no forecast reliability gaps in the T-1 timeframe (2020-21). Therefore, **AEMO will not be requesting any T-1 reliability instrument** in response to this 2019 ESOO.
  - Although the expected level of USE in Victoria in 2019-20 exceeds the reliability standard, this summer does not fall within the T-1 timeframe, and is therefore not relevant for the RRO.
- The closure of one unit at Liddell Power Station (450 MW) in April 2022 only results in a slight deterioration in forecast reliability in New South Wales in the T-3 timeframe (2022-23), with the expected USE at 0.0002%. As no region has USE in excess of the reliability standard in 2022-23, **AEMO will not be requesting a T-3 reliability instrument** in response to this 2019 ESOO.
  - Supply scarcity risks remain if the condition of Liddell (or any other power station) deteriorates to the point that closure ahead of these planned dates is unavoidable.
- Following the complete closure of Liddell Power Station (remaining 1,350 MW) in April 2023, the expected level of USE in New South Wales rises sharply (0.00174%) to be marginally below the reliability standard in 2023-24. While this does not currently constitute a forecast reliability gap, **in the absence of further market response, there are high risks of load shedding under extreme heat conditions** in that year. Supply and demand conditions in New South Wales will need to be carefully assessed in the lead up to the 2020 ESOO, to determine whether a T-3 reliability instrument request is required.
- In the absence of recommended new transmission interconnection between South Australia and New South Wales, the retirement of Osborne Power Station (172 MW) in 2023 causes expected USE in South Australia to increase significantly (0.0011%), but it remains within the 0.002% standard.
- Beyond 2022-23, there is only one year (2028-29) where the indicative reliability forecast identifies a potential reliability gap in New South Wales. Forecast reliability gaps are not identified for any other region or year, given that the materiality threshold for the reliability gap is that *expected* USE in a region should not exceed 0.002% of total energy demanded in that region for a given *financial year*.

6.1 Key assumptions

The reliability assessment assumes 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.
- Include existing and committed new entrant generation.
- Do not include either the expedited VNI or QNI augmentations currently under consideration through the RIT-T process (Chapter 8 shows the impact of these augmentations on reliability).
- Do not include other transmission investments that have not yet passed the regulatory approvals process[83], such as:
  - EnergyConnect (new interconnection between South Australia and New South Wales).
  - HumeLink (new transmission development to unlock congestion and enable benefits of Snowy 2.0 to be delivered to the NEM).
  - Proposed Western Victoria transmission developments that will reduce constraints on renewable generation development in the area.
- Do not include Tamar Valley CCGT in Tasmania, which Hydro Tasmania has advised is currently unavailable, but could be returned to service with three months' notice or less.
- Include only six of the eight units installed at Torrens Island Power Station from December 2019, as permission from the South Australian Government to allow AGL to continue operating the remaining two units over the coming summer is still pending.
- Do not include the South Australian temporary diesel generators that were installed the summer before last 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.

As the level of forecast USE observed in Queensland and Tasmania is negligible, these regions have been removed from the presentation of USE outcomes in this chapter.

Further details about reliability assessments by region[84] are in Appendix A2.

6.2 The reliability forecasts (first five years)

The 2019 ESOO shows that Victoria is expected to be above the reliability standard in Victoria in the coming summer, due to the risk that the current prolonged outages at the Loy Yang and Mortlake Power Stations extend over the height of summer. These risks are discussed further in Chapter 5.

As shown in Figure 32, after this summer, the level of USE risk in Victoria is projected to subside, primarily due to the removal of the likelihood of delayed return to service of the units currently on outage, noting that the risk of further prolonged generation or transmission outages occurring remains present. Lower peak demand expectations and further renewable generation development also provide modest contributions to the forecast reduction in supply scarcity risk.

This assessment does not:

- Fully take into account the possibility of similar long-term outages, particularly those caused by force majeure events.
- Consider the possibility of further deterioration in plant reliability which may occur as generators age.

[83] Work on these enabling transmission projects is being progressed by transmission network service providers (TNSPs), and will be further investigated in AEMO's 2019-20 ISP.

[84] This includes assessments under Slow Change and Step Change scenarios

The reliability outlook for New South Wales remains relatively positive over the coming four summers, but then expected USE increases steeply with the complete retirement of Liddell Power Station in April 2023. The expected level of USE in 2023-24 is only marginally below the reliability standard (0.00174%).

As generation is withdrawn in South Australia (Torrens Island A between 2019-20 and 2021-22 and Osborne in 2023-24), the level of USE rises to above 0.001% in 2023-24, but remains within the reliability standard.

Figure 32 Forecast USE outcomes, Central scenario

The RRO requires AEMO to identify whether there exists a reliability gap in any region. As this is the first year the RRO is in effect, the key year of interest is 2022-23 (the year T-3). A material forecast reliability gap is identified where the expected level of USE exceeds the reliability standard. As no region has USE in excess of the current reliability standard in 2022-23, AEMO will not be requesting a T-3 reliability instrument.

6.3 The indicative reliability forecasts (second five years)

The second five years (2024-25 to 2028-29) of the ESOO are also provided in Figure 32, which (along with 0) meets AEMO's requirement under the RRO to publish an *indicative reliability forecast*.

Although expected USE generally remains below the reliability standard in all regions excluding Victoria this summer, the risk of significant load shedding events throughout the 10-year outlook period remains high without further investment in resources or transmission as announced capacity retires.

The entry of Snowy 2.0 in 2025 does little to improve forecast reliability, because this modelling does not assume the commitment of transmission augmentations associated with the Snowy 2.0 development (HumeLink), as these augmentations have not completed the RIT-T process. As such, in this assessment, network capability to transfer between the Snowy Mountains and the load centre in Sydney remains a limiting factor in supplying peak demand in New South Wales.

As with Victoria, this forecast does not consider potential deteriorations in plant reliability as the generation fleet ages in New South Wales, particularly given the potential wear-and-tear impacts that come through imposing more flexible operating regimes on these power stations in response to great levels of large-scale renewable generation and rooftop PV.

The ESOO analysis assumes that the aging Liddell Power Station units remain in adequate condition to remain operational until the announced closure dates in 2022 and 2023. Any catastrophic failure of these units would advance the supply scarcity risks identified in the reliability forecasts from 2023-24 onwards. In the final year, 2028-29, expected USE in New South Wales rises again, driven by increasing demand, mainly due to forecast growth in EV uptake starting to become significant from this year.

The USE outlook for South Australia increases slightly as the Torrens Island A Power Station completes its withdrawal. Following the retirement of Osborne Power Station, USE increases steeply to sit at between 0.0008% and 0.0011% for the remainder of the ESOO horizon.

Comparison to 2018 ESOO reliability forecasts

Compared to the reliability outlook in the 2018 ESOO, beyond 2021-22, the level of USE shown in Figure 32 above has reduced across all regions, most noticeably over the long term. The primary driver of the improved reliability outlook is the reduction in expected peak demand relative to last year's forecast, particularly in New South Wales and Victoria, as shown in Figure 24 (for 50% POE) and Figure 25 (for 10% POE) in Section 3.2.

The 4,400 MW of committed capacity in this assessment that was not included in the 2018 ESOO makes only a limited contribution to reducing expected USE during high demand periods. Half of the new projects are variable renewable energy generators, which typically do not generate at full capacity during peak demand times or may be positioned in a congested part of the network. The full benefits of Snowy 2.0 (included in the 4,400 MW total) are not realised without the associated transmission development, as discussed above.

6.4 Forecast reliability gap size

Table 16 shows the additional megawatts of firm capacity required to meet the existing reliability standard in the first five years. The bolded year represents the critical year of the reliability forecast. The reliability gaps for each region over the second five years are provided for the indicative reliability forecast in 0.

Table 16 Forecast reliability gap (in MW) for RRO – the reliability forecast

Year	Gap (in MW) to meet the existing reliability standard			
	Victoria	South Australia	New South Wales	
2019-20	125	0	0	
2020-21	0	0	0	
2021-22	0	0	0	
2022-23	**0**	**0**	**0**	T-3
2023-24	0	0	0	

Table 17 Forecast reliability gap (in MW) for RRO – indicative reliability forecast

Year	Gap (in MW) to meet the existing reliability standard		
	Victoria	South Australia	New South Wales
2024-25	0	0	0
2025-26	0	0	0
2026-27	0	0	0
2027-28	0	0	0
2028-29	0	0	5

6.5 One-in-two year peak demand forecast

AEMO's one-in-two year peak demand forecast is what will trigger compliance obligations, should a T-1 reliability instrument be requested in the future. For this, AEMO uses its 50% POE operational maximum demand forecast on an 'as generated' basis. While no T-3 or T-1 reliability instruments have been requested, for information, AEMO has provided the forecast for the reliability forecast horizon in Table 18. Performance of these demand forecasts will be included in future Forecast Accuracy Reports. The only difference between Table 18 and the operational maximum demand values reported in Section 3.2 on a 'sent out' basis is the inclusion of auxiliary load forecasts at time of maximum demand.

Table 18 AEMO's one-in-two year peak demand forecast (50% POE, as generated)

Year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2019-20	13,807	9,942	3,038	1,741	9,253
2020-21	13,784	9,996	3,038	1,752	9,113
2021-22	13,740	10,051	3,030	1,745	9,014
2022-23	13,737	10,123	3,046	1,747	9,011
2023-24	13,614	10,166	3,065	1,747	8,991

AEMO forecasts 'sent out' operational demand, because this directly reflects the consumption to be supplied from the grid. 'As generated', on the other hand, requires assumptions about how many coal-fired plants (which have by far the highest auxiliary loads) are generating at the time. As this is uncertain, due to forced outages in the shorter term and changes to the generation mix in the longer term, there can be significant differences between forecast and actual outcomes in particular in the longer term. AEMO therefore generally presents forecast on a 'sent out' basis.

In the shorter term, including the five-year reliability forecast horizon, 'as generated' is more comparable with AEMO's short-term forecasts and actuals presented in near-real time[85], which is why AEMO is using this as the definition for the RRO one-in-two year peak demand forecast. Allowing comparison of forecast against actual demand in near-real time provides liable entities with the opportunity to act to reduce load when actual demand approaches the one-in-two year peak demand forecast.

Because the NEM uses 'as generated' terms for generator capacities (as reported in Chapter 4), AEMO models auxiliary load in its ESOO modelling, and the modelled auxiliary load has been used to convert the 'sent out' forecast of maximum demand to 'as generated'.

[85] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard#operational-demand.

7. Modification of the reliability standard

This chapter provides a summary of the key reliability issues facing the NEM over the next 10 years, and outlines the need for a modification to the reliability standard to ensure there are sufficient reserve resources in the NEM in nine out of 10 years.

Increasing risks of uncontrollable, high impact events

- The 2019 ESOO continues to highlight that there are significant risks to the reliability of supply in Victoria this summer, and in New South Wales (from 2023-24) and South Australia (from 2023-24), following the withdrawal of generating capacity.
- The NEM has seen a continued reduction in dispatchable reserves and a tightening in supply-demand balance as conventional generation has retired. At the same time, while large amounts of renewable generation have entered the system, the reliability of the aging thermal generation fleet has deteriorated and the warming climate has increased the risk of extreme temperatures and high peak demands.
- These factors combined increase the likelihood of tail risk events. Such events are not fully visible under the current reliability standard because it requires USE to be averaged across the full range of possible outcomes for a given financial year.

Mitigating these risks by refining the reliability standard

- To reduce the likelihood of these uncontrollable, high impact events leading to significant load shedding, AEMO has used the built-in flexibility of the current reliability framework to operationalise the reliability standard to the extent permissible within the NER. This has included:
  - Reviewing the probabilities associated with the tail risk of the USE distribution, and
  - Reviewing and updating inputs and assumptions used in calculating the USE, in consultation with industry.
- However, as acknowledged by the AEMC in its Final Determination on the enhancement to the RERT Framework, using AEMO's current probabilistic modelling approach, there is a "clear mathematical link between the reliability standard as defined in the NER and the process for determining whether the reliability standard is met"[86].
  - Because of this mathematical link, AEMO has limited flexibility to operationalise the existing standard in any way other than by calculating the expected annual USE using the best assumptions available.

[86] See page 40, at https://www.aemc.gov.au/sites/default/files/2019-05/Final%20Determination.pdf

- AEMO does not believe that this approach adequately protects customers from involuntary load shedding during extreme weather conditions.

- AEMO therefore proposes a reliability framework that enables AEMO to forecast and, if necessary, procure sufficient dispatchable resources to avoid customer exposure to significant involuntary load shedding in approximately nine out of 10 years. AEMO will work with jurisdictions and industry to propose a revised reliability framework that better addresses consumer risks in the transitioning power system.

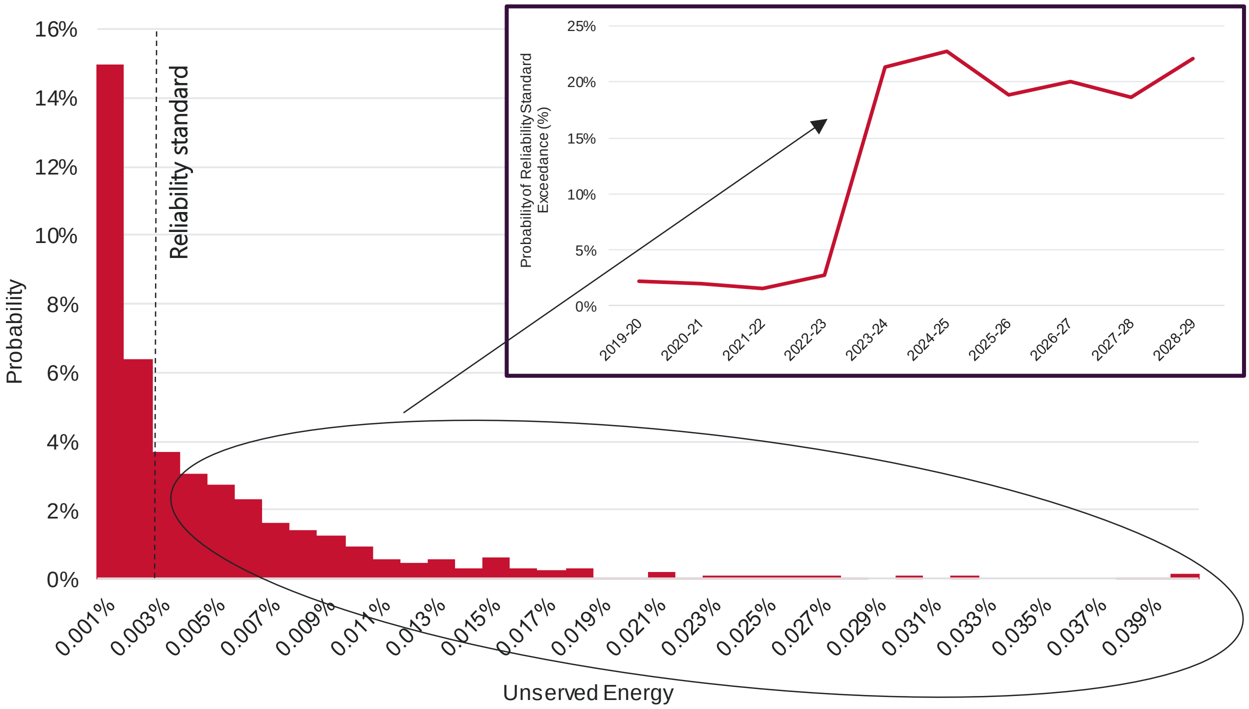
7.1 Operationalising reliability

7.1.1 Operationalising the standard within the current reliability framework

AEMO's NEM Reliability Framework paper[87], published as an addendum to the enhanced RERT rule change, highlighted that the current NEM reliability framework must be able to deal with increasing tail risk, but is not well suited to this task. Instead, it revolves around the comparison of the expected USE measure of reliability to a single 0.002% reliability standard as the means of triggering a response. This expected USE, representing the weighted average outcome, does not adequately describe the wider shape of the distribution of USE outcomes and in particular the severity of the tail risk.

These tail risks are well illustrated by looking at the distribution of USE outcomes for New South Wales in 2023-24 following the staggered closure of Liddell Power Station. While expected USE is below the reliability standard, analysis indicates a 21% probability that USE will exceed 0.002% in 2023-24 (see Figure 33).

Figure 33 Distribution of annual unserved energy in NSW 2023-24



Depending on the coincidence of unplanned outages and extreme weather events, load shedding could be experienced during an extreme one-in-10 year heat event, equivalent to between 135,000 and 770,000

[87] See https://www.aemc.gov.au/news-centre/media-releases/additional-information-aemo-reliability-standard-and-rert-have-your-say.

households in New South Wales being without power for three hours, potentially over multiple events. A one-in-10 year demand event might occur when temperatures range from 39⁰C to 46⁰C.

Moreover, while the existing standard targets reliable supply of 99.998% of annual demand, most USE events typically occur in the summer months of January and February. In New South Wales in 2023-24, 0.002% of total annual energy is equivalent to 1,300 MWh. If all of this load was shed over these two months of the year, this would represent 0.012% of the load in summer.

In its Final Determination to the enhanced RERT rule change, the AEMC acknowledged that the power system is changing, with changes in generation mix and greater exposure to the vagaries of weather leading to a power system that is more volatile and harder to operate. To address these challenges, the AEMC recommended that AEMO maximise use of the flexibility already available within the current reliability framework to operationalise the reliability standard. Suggestions provided by the AEMC for doing this, in consultation with industry, included:

- Adjusting forced outage rates on generators, if there was evidence of deteriorating reliability.
- Changing the demand forecasting approach to better capture extreme weather events.
- Incorporating uncertainty – capturing errors in assumed temperature forecasts or generator availability.
- Changing the weighting of some of the 10% POE demand outcomes in the Reliability Standard Implementation Guidelines, through consultation with industry.

AEMO has taken these suggestions on board in developing the 2019 reliability forecasts.

Adjusting forced outage rates, and other assumptions

As discussed in Section 4.2.1, AEMO considers there is sufficient statistical evidence of deterioration in brown coal generation reliability to change its assumptions around future performance of the generation fleet, which it has done this year. Further work is still ongoing to better understand the future likelihood and impact of prolonged unplanned generation outages, as currently experienced, and to undertake studies to benchmark actual and projected performance against international experience.

Changing the demand forecasting approach to better capture extreme weather events

For the first time this year, AEMO has applied an ensemble of models to develop its maximum demand forecasts, including a generalised extreme value model that is better at forecasting short-term maximum demand.

AEMO also continues to work with the BoM and CSIRO through the Electricity Sector Climate Information (ESCI) project to better capture extreme weather events in its demand forecasting.

Incorporating uncertainty

As discussed in Chapter 5, AEMO has assessed the expected USE in 2019-20 by accounting for the estimated probability that at least one and possibly both units currently undergoing extensive repairs (Loy Yang A2 and one unit of Mortlake) will experience a delay in their return to service.

However, the range of possible outcomes this summer is still very broad, and the magnitude of supply scarcity risks will depend on whether outages are extended or not. By the time the certainty is sufficient to act with the current tools, the time to respond may have passed. For example, AEMO might have a very high degree of certainty in early December this year that a generator outage in Victoria will extend over the summer. However, this knowledge would be of very limited practical value, because there would be insufficient time to physically procure, install, and connect the necessary emergency reserves.

Changing the weighting of USE outcomes

Calculating expected USE is very computationally intensive and requires simulations for a wider number of POEs to be effective. It can, however, be estimated using weightings of USE outcomes for a limited number of POEs. This is currently required to complete the ESOO within reasonable time and cost.

In its 2018 ESOO, AEMO discussed weightings of POEs in detail following review of the weightings that had historically been applied[88].

It presented the current weightings – 30.44% weighting of 10% POE, 39.12% for 50% POE, and 30.44% for 90% POE – and that these are derived from the mathematical concept of Taylor expansion of the estimated USE as function of the POE demand outcomes[89]. The advantage of this approach is that neither the parameters of the normal distribution, nor the USE function[90], need to be known. This makes them simple to apply.

These weightings are exact, if the following conditions hold:

- 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.

However, statistical tests show that maximum demand outcomes are not normally distributed. AEMO tested the accuracy against a much more detailed approximation of USE in a particular year, that had used additional simulations for other POEs to make it more accurate. It was found the mathematical approximation worked well across different regions' and different years' analysis, and also allowed weighting of different metrics than USE, such as the loss of load probability (LOLP).

Further analysis undertaken this year with additional data from the BoM to inform the tail end of the distribution (higher demand than 10% POE outcomes) shows the mathematically derived weightings are within 10% of the more detailed approximate outcomes.

This shows that refining the weightings will at best lead to minor changes to results, and will not allow AEMO to manage tail risks effectively. Furthermore, by the time there may be greater certainty that a particular region is likely to experience a one-in-10 year peak demand, there will be insufficient time to meaningfully prepare for this outcome.

Breaking the mathematical link

The reliability standard is clearly defined in clause 3.9.3C(a) of the NER as: "a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year".

For the ESOO, AEMO currently applies probabilistic simulations of possible future demand and supply outcomes to calculate the *expected* value of possible annual USE outcomes, and therefore preserves a direct mathematical link between the standard and how AEMO implements, or operationalises, the standard.

AEMO does not consider that it is possible to propose a defendable and credible alternate assessment approach that breaks this link without change to the standard as articulated in 3.9.3C(a) and accompanying Guidelines.

An *expected* value is a well-defined mathematical concept. To calculate an expected value, the probability weights for potential outcomes have to be chosen such that they are representative of the likelihood of each particular outcome occurring. Furthermore, the standard requires AEMO to calculate outcomes over a whole year. It is therefore unable to focus the calculation on specific periods, such as the critical summer period.

7.1.2 The need for greater flexibility to adequately achieve system reliability

By having to use *expected* values of USE, uncontrollable but increasingly likely, high impact ('tail risk') events are masked in the current reliability standard, and AEMO lacks the flexibility to manage these risks.

[88] See Appendix A3 of the 2018 ESOO, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

[89] In practice, USE for 90% POE demand outcomes are generally zero or very close to. To improve the quality of the estimate of 10% and 50% POE outcomes where USE generally occurs, simulations for 90% POE is generally omitted and USE simply assumed to be zero.

[90] Should USE be better approximated by a higher order polynomial, more weightings can be added, where four POE weightings represent an approximation by a third order polynomial, five weightings can approximate a fourth order polynomial.

In this ESOO, given the increasing amount of tail risk with its potentially devastating effects, AEMO requires greater flexibility to achieve system reliability in a way that better captures the risk from uncontrollable, high consequence events. The reliability component of the National Electricity Objective could be improved significantly by modifying the current standard to:

> '***Ensure there are sufficient dispatchable reserves (MW) available in each region such that USE is forecast to be less than 0.002% of total energy demanded in that region in 9 out of 10 years***.'

This approach draws on much of the same analysis as currently used to calculate the *expected* USE under the current reliability standard. The key difference is that it focuses on the *likelihood* of USE being less than 0.002% of total energy demanded in that region, instead of the *expected* USE being less than 0.002%.

Example: calculating the likelihood of USE exceeding 0.002% of total energy demanded

For illustrative purposes, assume 100 random sample years were simulated, featuring different generator outages, demand conditions, and renewable generation outputs. The forecast annual USE is then calculated for each sample:

- To assess *expected* USE, the weighted-average annual USE across all 100 samples would be calculated and compared against the reliability standard.
- To assess *likelihood* of USE being less than 0.002% of total energy demanded in nine out of 10 years, the **proportion** of samples with annual USE above 0.002% would be calculated, rather than **averaging** the samples. For example, if 15 out of 100 samples showed USE above 0.002%, then the probability of reliability standard exceedance would be calculated as 15%.

The level of reliability forecast to be achieved through this approach would be an improvement over current forecasts because, in effect, this is a more conservative standard operationally, but it would not deliver a power system that is as reliable as some jurisdictions internationally. For example, the ERCOT, PJM, ISO-NE, Midwest ISO, and NY ISO in North America all apply reliability standards broadly consistent with one loss of load event or day every 10 years (0.1 events or 2.4 hours per year), irrespective of the magnitude of the event[91]. RTE-France targets sufficient capacity to meet a one-in-10 year winter peak. As part of its proposal for a revised standard, AEMO will provide more analysis to determine if these alternative approaches should be adopted.

When pursuing system reliability, great care needs to be taken to minimise the associated cost to consumers and to allocate this cost in an equitable fashion. Additional reserves could come from demand response, energy storage, improved interconnection, dispatchable generation, or other resources. The actual cost of the additional reserves required to meet this standard would depend on the way it would be implemented.

By using a well-designed and predictable market mechanism that captures the full range of low cost or value-adding opportunities for response, such as demand response, virtual power plants (VPPs), and strategic interconnectors. AEMO believes long-term costs could be lower than the Value of Customer Reliability (VCR)[92].

In particular, by having demand response and other customer energy solutions as part of the reserves mix, it would maximise consumer choice. Consumers who prefer lower prices over higher reliability can achieve this by providing demand response services, and consumers who expect a higher level of reliability can enjoy the full benefits of the higher standard.

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[91] The Brattle Group and Astrape Consulting, *Resource Adequacy Requirements: Reliability and Economic Implications*, 2013, Table 14, at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf.

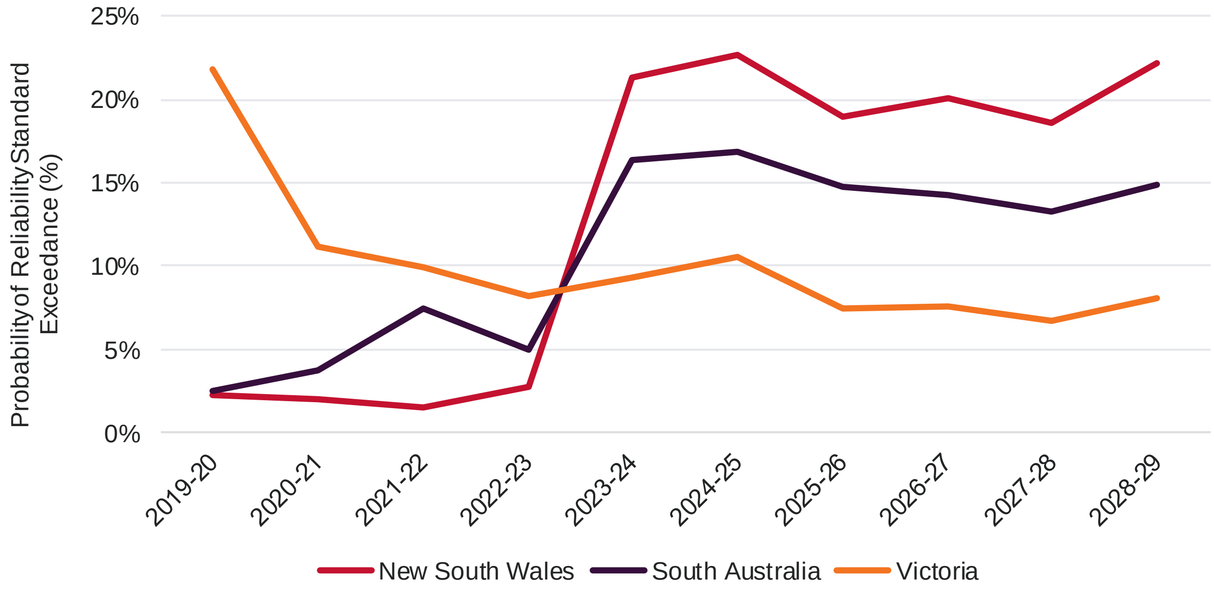
[92] The VCR represents a customer's willingness to pay for the reliable supply of electricity. For information, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

7.2 Additional reserves required under a more flexible framework

Figure 34 shows the probability of the reliability standard being exceeded if no further investment occurs beyond what is current committed. It shows that the probability of the reliability standard being breached significantly exceeds 10% (as AEMO's proposed target level in the operationalised standard) in Victoria (from now until 2021-22), New South Wales (from 2023-24 onwards), and South Australia (from 2023-24 onwards).

In New South Wales, for example, in the years following the Liddell retirement there is a risk of 19-23% that the level of USE would exceed the current reliability standard. Under extreme summer conditions that drive demands up towards the 10% POE level, the probability of load shedding in excess of 0.002% would be much higher. To put this in perspective, 0.002% USE is equivalent to 660,000 households in New South Wales without power for one hour, and such outages could occur once every four to five years.

Figure 34 Forecast probability of reliability standard exceedance, Central scenario



For regions where forecast reliability gaps are close to, or exceed, the current reliability standard, Table 19 shows the megawatts required to achieve the current reliability standard (as in Table 16 and 0 in Chapter 6), and to achieve the alternative refined standard.

Depending on the region, up to 475 MW more reserves would be needed from an operational perspective to increase the likelihood that the reliability standard will be met nine out of 10 years.

Table 19 Reliability gap (in MW) based on both the current and refined reliability standard

Year	Gap to meet the existing reliability standard			Gap to meet the proposed refined standard		
	Victoria	South Australia	New South Wales	Victoria	South Australia	New South Wales
2019-20	125	0	0	560	0	0
2020-21	0	0	0	35	0	0
2021-22	0	0	0	0	0	0
2022-23	0	0	0	0	0	0
2023-24	0	0	0	0	135	375
2024-25	0	0	0	0	150	375
2025-26	0	0	0	0	95	300
2026-27	0	0	0	0	100	345
2027-28	0	0	0	0	70	300
2028-29	0	0	5	0	105	480

Impact for Victoria this summer

If this refinement to the reliability standard were to be adopted in Victoria this summer, it would reduce the risk of load shedding events significantly. To reduce the likelihood of exceeding the reliability standard to a one-in-10 year event, a total of 560 MW of firm capacity would be required instead of the 125 MW identified to meet the current reliability standard.

Also, with 560 MW of additional firm supply, even if neither of the two units on extended outage returned to service in January and February, the expected level of USE would remain below the standard (0.0016%). In this scenario, under extreme heat contributing to one-in-10 year demand conditions, USE in excess of the reliability standard may still be observed.

If the South Australian Government grants AGL permission to continue operate all four Torrens A units over summer, the additional capacity required to limit the risk of exceeding the standard to 10% would fall from 560 MW to 420 MW.

Impact for New South Wales after Liddell closes

If the proposed modification to the reliability standard was to be adopted by summer 2023-24, and action taken to meet it, it would reduce the risk of load shedding events significantly in New South Wales.

While expected USE is 0.00174% in 2023-24, which is within the current standard, there is a significant risk that actual USE may be significantly higher than 0.002%. AEMO projects a 21% probability that USE will exceed 0.002% in 2023-24 (see Figure 33). A total of 375 MW of additional reserves would be required to reduce the chance of load shedding in excess of 0.002% to a one-in-10 year likelihood.

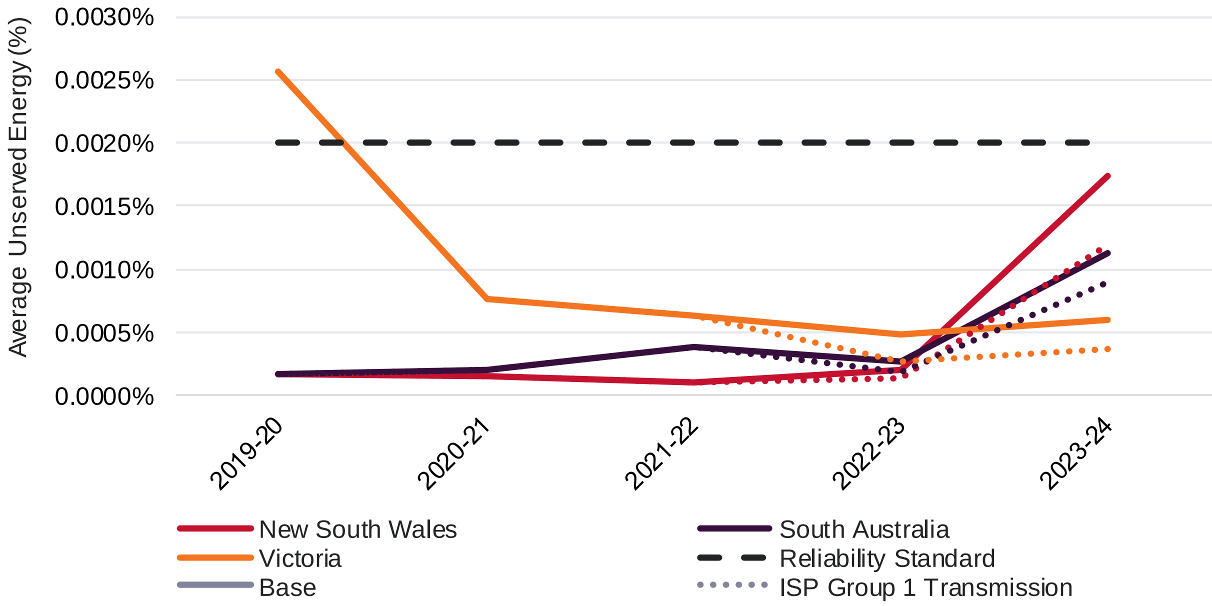
8. The value of transmission and DER

This chapter discusses in more detail the reliability benefits that can be derived from greater interconnection and DER.

The 2018 ISP identified a number of priority transmission augmentations that were required to maximise the use of existing generation assets. In particular, the ISP identified two relatively minor transmission augmentations between New South Wales, Queensland, and Victoria which could provide immediate benefits in terms of both reliability and economic benefits to consumers.

AEMO has considered a sensitivity that considers the impact of these augmentations in the first five years of the modelling horizon (see the assumptions outlined in Section 4.4.3). Figure 35 shows that these minor augmentations improve the USE outlook in all three regions experiencing reliability risks.

Figure 35 Impact of ISP Group 1 Transmission projects on USE, Central scenario

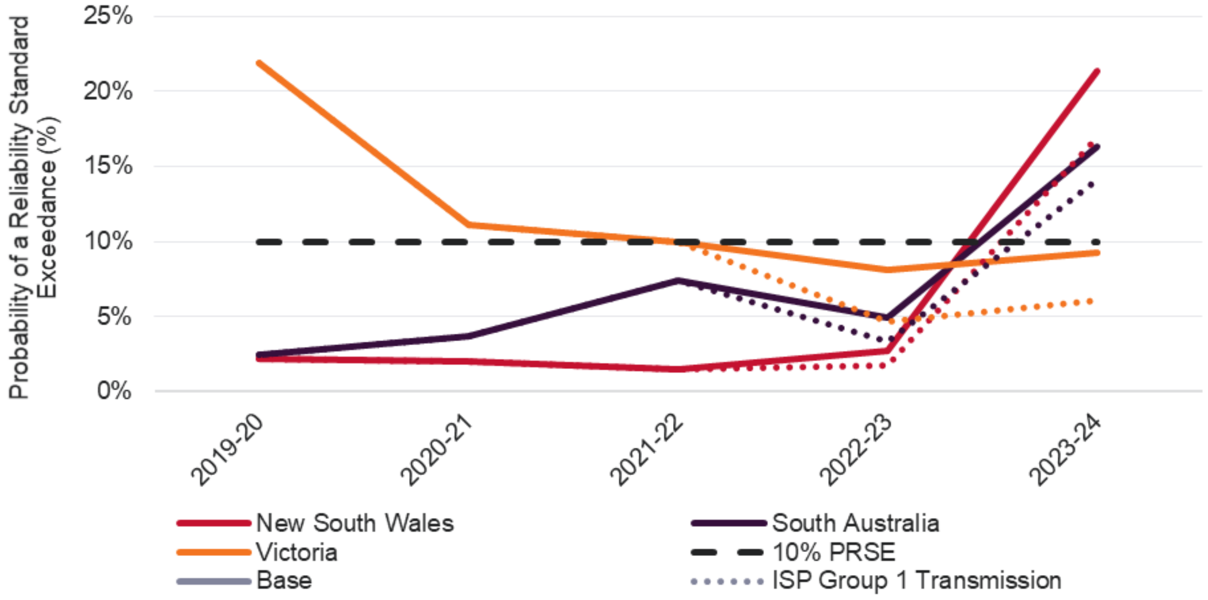


Should these two projects be implemented by 2022-23 as assumed, the tail risk will reduce significantly, but the probability of reliability standard exceedance is still above 10% in New South Wales and South Australia, as shown in Figure 36.

With these transmission investments in place, additional dispatchable capacity requirements determined using the modified reliability standard proposed in Chapter 7 are projected to reduce in 2023-24 from 375 MW to 215 MW in New South Wales, and from 135 MW to 90 MW in South Australia in 2023-24.

The augmentations considered in this sensitivity do not include major augmentations such as EnergyConnect (between South Australia and New South Wales) or the developments associated with Snowy 2.0 (HumeLink and KerangLink). These augmentations could substantially improve reliability across the regions by increasing the ability to share surplus reserves and unlocking the extra capacity provided by Snowy 2.0.

Figure 36 Impact of ISP Group 1 Transmission projects likelihood of USE >0.002%, Central scenario

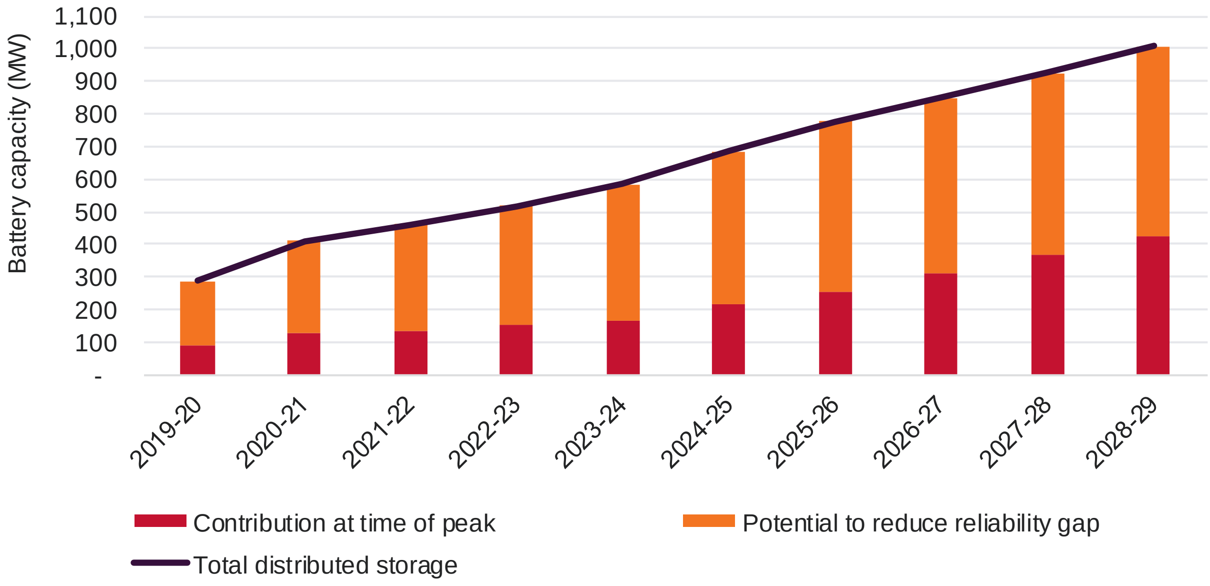


Potential role of distributed energy resources

The forecast increase in DER uptake has the potential to play a key role in addressing reliability gaps that emerge as generation withdraws from the market. However, the modelling of DER in the ESOO, particularly battery storage capacity, reflects uncertainty around how these systems will operate in the future. The majority of the battery systems are assumed to operate according to a profile centred around retail tariffs. As such, these systems do not necessarily respond to wholesale market signals in a way that maximises their ability to moderate peak demand. The systems that are modelled as VPPs are optimised within the supply model, and therefore operate to reduce USE to the maximum extent possible.

Figure 37 shows an estimate of the total contribution from DER to reducing peak demand across Victoria, South Australia, and New South Wales, compared to the total installed capacity of battery storage systems.

Figure 37 Forecast maximum potential of DER in Victoria, South Australia, and New South Wales, 2019-20 to 2028-29



This shows that, if better coordinated, there is the potential for DER to provide up to 580 MW of additional supply at times of peak demand by 2029[93].

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.

AEMO has commenced a broad program of work aimed at integrating DER into the system and market[94], and is working closely with the Energy Networks Association (ENA), AEMC, AER, Australian Renewable Energy Agency (ARENA), and industry players to deliver on focus areas including:

- DER visibility – AEMO's DER Register will be implemented from 1 December 2019. This will enable AEMO to explore more granular visibility of DER installed across Australia. The register's database of DER assets will inform operational and market processes, particularly as these resources are integrated into the grid and market dispatch processes.
- DER capability – AEMO has commenced a program of work called the DER Standards Stream, which aims to improve the performance and capability of DER in ways that are consistent across the energy system. The first report in this workstream is the Technical Integration of Distributed Energy Resources Report[95], published in April 2019, which shares AEMO's preliminary findings to date on the behaviour of DER during disturbances and proposes the development of improved DER performance standards and DER dynamic models.
- 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.

[93] 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.

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

[95] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

- 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 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. AEMO opened up a VPP Demonstrations program for registration[96] on 31 July 2019.

[96] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations.

9. Summary of actions

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.

AEMO has identified a number of prudent and least-cost actions that should be taken to avoid consumer exposure to an unreasonable level of risk of involuntary load shedding during peak summer periods. Some of these actions are currently underway and should be pursued without unnecessary delay. Others will require changes to rules and/or additions to AEMO's authority.

AEMO will seek to implement these recommendations through its continued work with Commonwealth and State Governments, the ESB, the AEMC, and the AER.

1. **Summer readiness plan** – as it does every year, AEMO is already working proactively with industry and governments to prepare for the coming summer by implementing a comprehensive summer readiness plan to minimise risks as much as possible within the current rules framework. This year, AEMO is also working in depth with generators and industry experts to gain a better understanding of forced outage rates of aging generators to improve future reliability assessments, in particular in light of the increasing frequency of hard to predict but high impact events such as unplanned outages of dispatchable supply resources.
2. **Commissioning of targeted transmission augmentation** – the supply-demand balance in New South Wales will be significantly improved with the addition of the QNI and the New South Wales component of the VNI upgrades and, once completed, through HumeLink and EnergyConnect, as identified in the 2018 ISP. This ESOO reconfirms the importance of the work now underway to complete QNI and VNI ahead of the closure of Liddell Power Station, involving significant undertakings by governments, industry, the ESB, and the AER. To enhance the resilience of the NEM against the growth of systemic risks during the energy transition (for example, to enable the system to absorb the impact of deteriorating performance of aging plants), a new mechanism will be required for the fast-tracked delivery of 'no regrets' transmission infrastructure and transmission infrastructure that could deliver important reliability and resilience benefits. The 2019-20 ISP will identify essential 'no regret' and resilience projects, and AEMO will work with governments, industry, market bodies, and the ESB to develop a process by the end of 2019 to implement them.
3. **Dispatchable resources** – once the above transmission infrastructure is in place, AEMO's analysis projects that new dispatchable supply of approximately 215 MW would be required to ensure New South Wales only has a one-in-10 year risk of a significant involuntary load shed event in summer 2023-24, following the full closure of Liddell Power Station. Over the coming two months, AEMO will work with industry and governments to identify the attributes and location of dispatchable resources that will address this risk and available mechanisms to assure the necessary investment.
4. **Reliability standard** – the current reliability standard is based on the *expected* USE within a given financial year not exceeding 0.002%. Because applying this standard requires the averaging of annual USE over all possible outcomes, it effectively averages out the risk of experiencing the rapidly growing number of events which can cause severe load shedding over the summer period. While AEMO has attempted to 'operationalise' the risks within the existing standard as much as possible, a modified reliability framework that enables AEMO to ensure customers are not exposed to significant involuntary load shedding in nine out of 10 years is necessary. AEMO will accordingly pursue the development of a modified standard over

the coming three months that can more cost-effectively and reliably provide the requisite level of dispatchable resources.

5. **Three-year strategic reserve** – in view of the current risk in Victoria, AEMO believes its inability to procure reserves over a three-year duration is imposing unnecessary risks and costs on Victorian consumers. AEMO will therefore continue look to obtain the necessary and prudent flexibility that maintains reliability at the lowest cost.
6. **Wholesale demand response** – AEMO is reviewing the recent decision of the AEMC to support the introduction of wholesale demand response in the NEM. As envisioned by the AEMC, AEMO will look for ways to accelerate participation by customers as a mechanism to support future reliability.
7. **Market reform** – the current forecast reliability risks, and the need for market-based investments, demonstrate the imperative to implement reforms in the NEM covering a number of areas. They include, for example, short-term forward markets, firming and security services markets, and markets to support investments at the right time and the right location, including nodal pricing and improved reliability mechanisms. AEMO will continue to work with the ESB and the other market bodies to help prioritise and progress market reforms that will improve how market participants can address consumer demands for reliable, secure, and affordable power.
8. **Notice and mechanism of closure** – the current three-year notice of closure rule for generators does not fully protect consumers from potentially significant high price and load shedding risks in the lead up to, and following, a major generator closure. As generators approach decommissioning, the risk of a major outage or unforeseen early exit due to economic consideration increases. Furthermore, the three-year closure period may not provide sufficient time to implement the most cost-effective replacement option, leading to higher cost outcomes for consumers. AEMO will work with governments, the ESB, and other market bodies to develop a proposal over the coming six months to refine the current rules to enhance long-term certainty of generator exit dates, while ensuring plant reliability in the lead up to the planned closure date.
9. **Information transparency** – AEMO is working with industry to increase the frequency and improve the content of information it publishes, to provide greater transparency and thereby improve decision-making. Improvements will include quarterly updates on generator commissioning and commitment in Generation Information Page updates[97]. AEMO will also investigate further generation, storage, demand side participation (DSP), and transmission measures in its upcoming 2019-20 ISP.

[97] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

A1. Regional demand forecast outlook

The following sections outline consumption and maximum/minimum demand outlooks for each region in the short term (0-5 years), medium term (5-10 years), and long term (10-20 years) for the Central scenario[98]. Each section also explains what time of day maximum demand is likely to occur and how this may change with uptake of rooftop PV, as well as the range of temperatures that may lead to different demand POE outcomes.

A1.1 New South Wales

Annual consumption outlook

The forecast operational consumption in New South Wales is relatively flat. The 2019 Central Scenario is lower than the 2018 Neutral forecast, due to increased uptake of EE measures, greater consideration of the structural change that continues to affect the business sector by moving away from energy-intensive manufacturing, and revised EV forecasts.

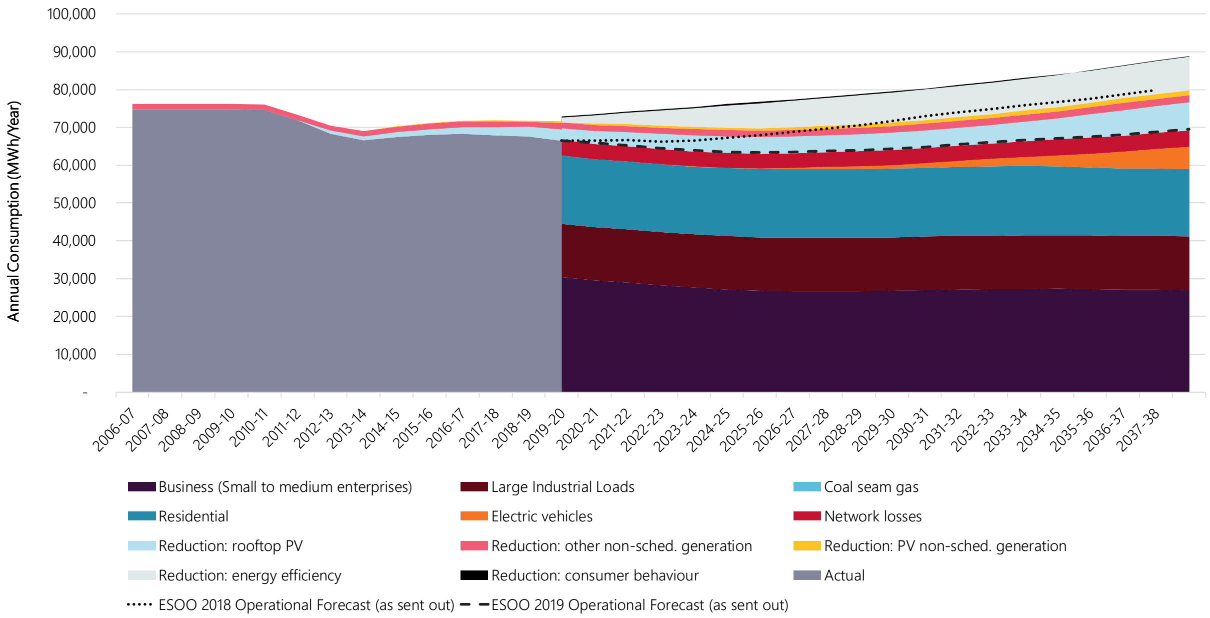
The forecast can be examined across the short, medium. and long term. as follows:

- In the short term (0-5 years) – operational consumption is forecast to decrease from 68 TWh in 2018-19 to 63 TWh in 2024-25 (-1% average annual growth rate). EE measures incentivised through Commonwealth and State Government schemes, including the New South Wales ESS, continue to lower underlying energy consumption in both the business and residential sectors.
- In the medium term (5-10 years) – operational consumption is forecast to increase slightly from 63 TWh in 2024-25 to 64 TWh in 2028-29 (0.2% average annual growth rate). This scenario does not extend the measures of the ESS scheme beyond current targets, as the scheme is legislated to end in 2025.
- In the long term (10-20 years) – operational consumption is forecast to increase from 64 TWh in 2028-29 to 69 TWh in 2038-39 (0.8% average annual growth rate).

Figure 38 shows the component forecasts for regional consumption in New South Wales.

[98] Data for additional scenarios is available on: http://forecasting.aemo.com.au.

Figure 38 New South Wales operational consumption in MWh, actual and forecast, 2006-07 to 2038-39



Maximum demand outlook

- Short term (0-5 years) – maximum operational demand is expected to remain relatively flat with an average annual growth of -0.3% to 2023-24. Growth over the next couple of years is consistent with what was forecast in the 2018 ESOO. The range between the 90% POE and the 10% POE is narrower than the 2018 ESOO forecast, because new modelling techniques allow for non-constant variance over time, resulting in narrower variance in the most recent years compared to the variance in the first half of the 2010s. This results in the 50% and 90% POE forecasts having a higher starting point than in the 2018 ESOO.
- Medium term (5-10 years) – the New South Wales maximum demand forecast remains flat (0.2% average annual growth to 2028-29), whereas in the 2018 ESOO there was a small decline initially and demand started trending upward after 2019-20. This flatter projection in the 2019 ESOO is due to lower business growth driven by higher forecast EE, partially offset by growth in residential demand due to growth in residential connections.
- Long term (10-20 years) – maximum demand in New South Wales is forecast to grow slowly again (0.7% average annual growth to 2038-39) as EE moderates. The growth rate is lower than forecast in the 2018 ESOO. This is driven by lower business demand due to higher EE, less EV charging at time of maximum demand, and greater battery storage discharging at time of maximum demand.

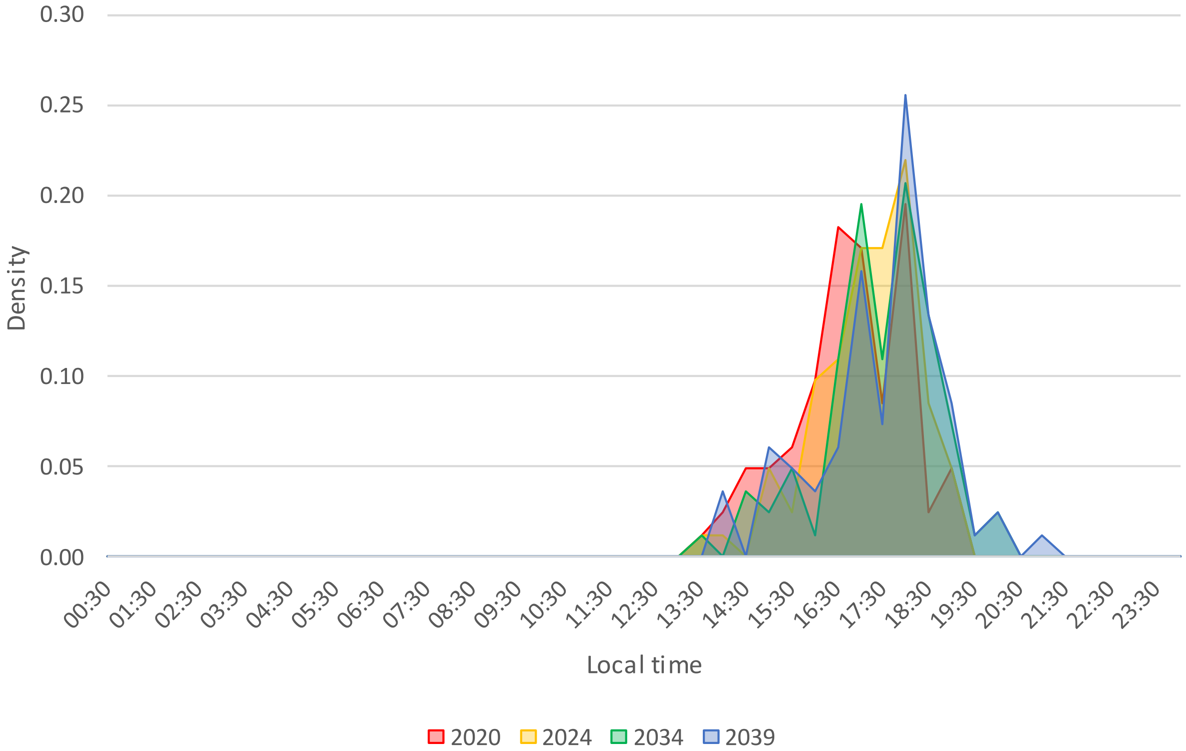
Characteristics of maximum demand outcomes

New South Wales typically experiences maximum operational demand between 15.00 to 18.30 currently (at the 80% confidence interval).

At this time, the impact of rooftop PV and PVNSG is expected to continue to have some impact on maximum demand.

As rooftop PV uptake increases, maximum demand is forecast to shift later in the day to between 15.30 to 19.30, as shown in Figure 39.

Figure 39 Distribution of forecast time of 50% POE summer maximum demand in New South Wales

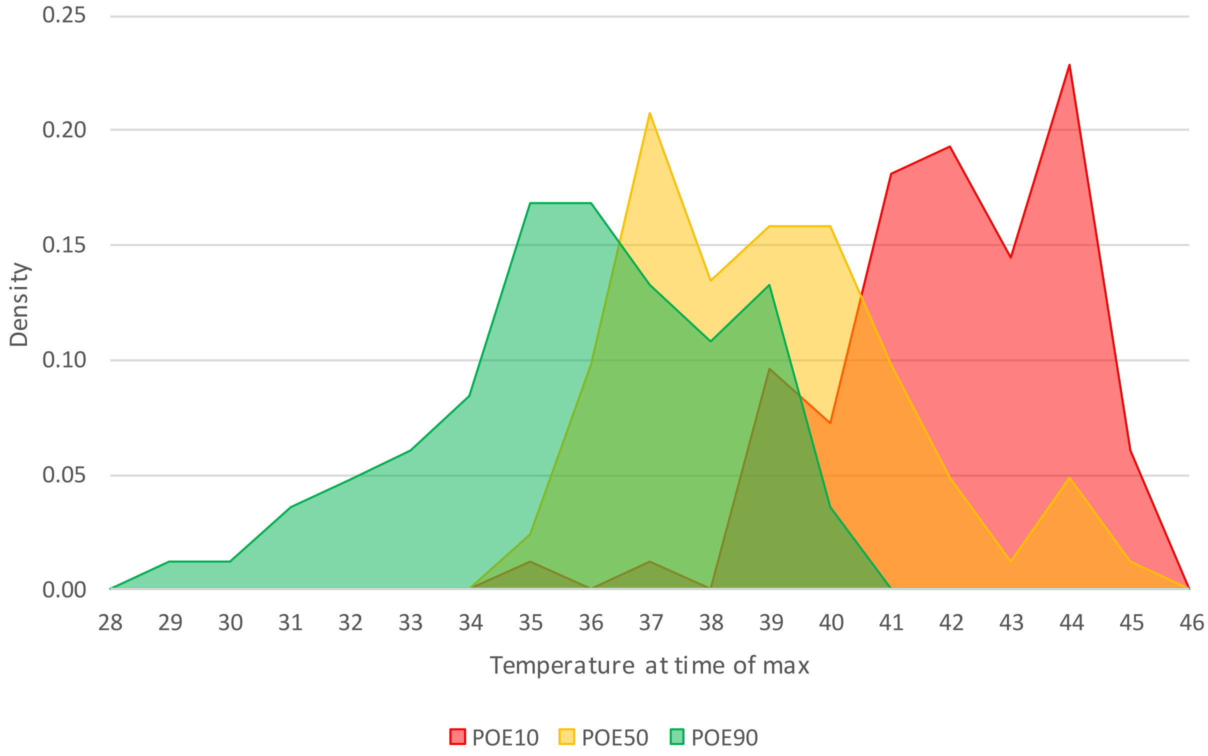


Maximum demand can occur due to a variety of conditions, high temperature, or heatwaves (daily rolling average of temperature) driving up demand, or low solar output.

In New South Wales, based on model simulations, a 10% POE maximum demand can occur between 38°C to 45°C, a 50% POE between 35°C and 43°C, and a 90% POE between 30°C and 39°C, as shown in Figure 40.

PV generation at time of 10% POE is lower than 50% POE by around 200 MW. This is largely governed by the expected time of day that maximum demand may fall, as discussed above.

Figure 40 Distribution of temperature at time of forecast summer maximum demand in New South Wales



A1.2 Queensland

Annual consumption outlook

Increased business activity more than offsets declining residential consumption in Queensland's operational consumption forecasts for the 2019 Central scenario. 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 levels – faster than previously forecast in the 2018 ESOO.

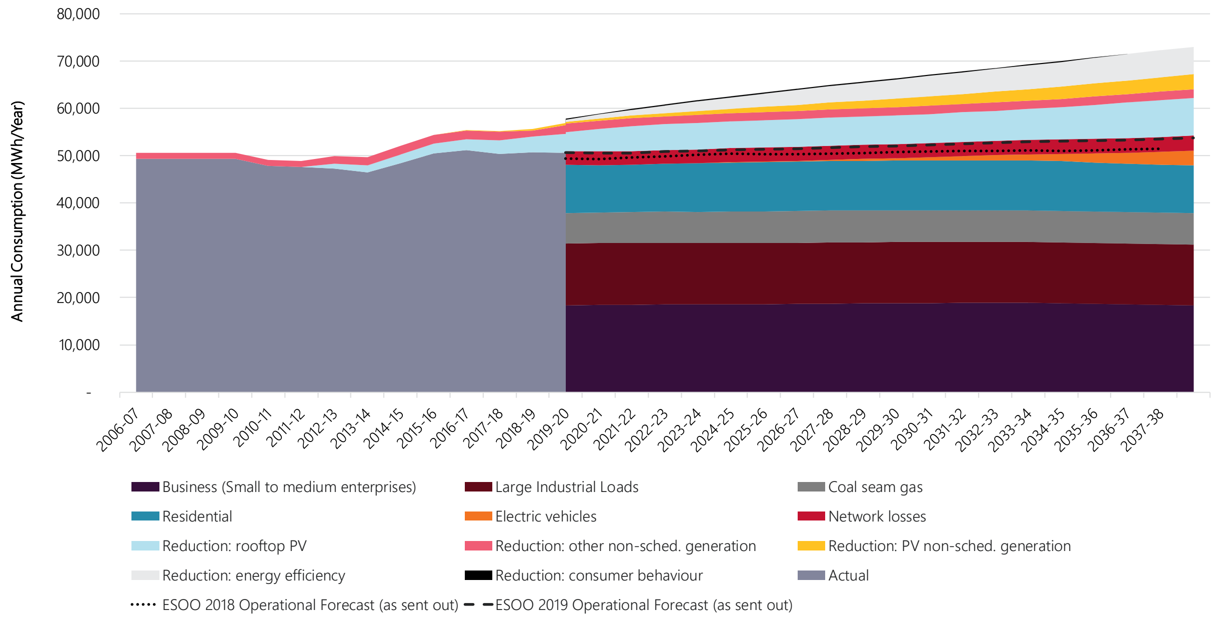
Residential consumption on the other hand is lower than previously forecast in the 2018 Neutral scenario. Similar to other NEM regions, EE forecasts are higher and EV capacity has been revised downwards due to lower national vehicle sales projections, and the inclusion of ride share assumptions. Rooftop PV capacity is forecast to be higher in the short term but then lower compared to the 2018 Neutral scenario, reflecting stabilising electricity prices.

The regional forecast can be examined across the short, medium, and long term as follows:

- In the short term (0-5 years) – operational consumption is forecast to increase slightly from 51 TWh in 2018-19 to 52 TWh in 2024-25 (0.3% average annual growth rate).
- In the medium term (5-10 years) – operational consumption is forecast to increase slightly from 52 TWh in 2024-25 to 52 TWh in 2028-29 (0.3% average annual growth rate – numbers are rounded).
- In the long term (10-20 years) – operational consumption is forecast to increase from 52 TWh in 2028-29 to 54 TWh in 2038-39 (0.4% average annual growth rate).

Figure 41 shows the component forecasts for regional consumption in Queensland.

Figure 41 Queensland operational consumption in MWh, actual and forecast, 2006-07 to 2038-39



Maximum demand outlook

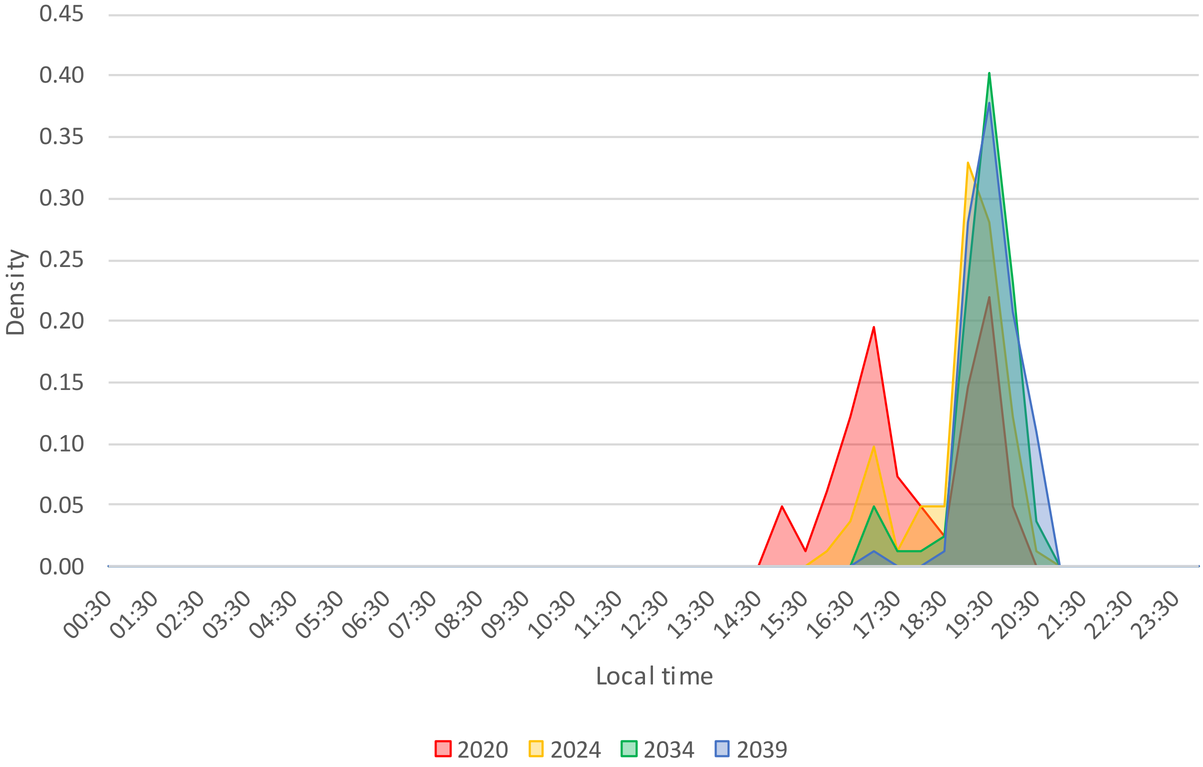
- Short term (0-5 years) – Queensland maximum operation demand exhibits a strong upwards trend (0.6% average annual growth), having risen roughly 800 MW since 2016 due to CSG and increasing cooling load. CSG is forecast to grow by 0.7% on average per year. The residual growth trend is also expected to continue to grow in the short term. The spread of POEs in the 2019 ESOO forecast is narrower than in the 2018 ESOO forecast, due mostly to improved modelling approaches increasing forecast confidence. Furthermore, the ESOO 2019 forecast for summer 2019-20 is higher than the 2018 ESOO.
- Medium term (5-10 years) – Queensland is the only NEM region forecast to grow by 0.5% average annual growth. The growth is consistent with the 2018 ESOO forecast. Residential and business consumption are expected to grow at a faster rate compared to components like rooftop PV, batteries, and EVs, putting upward pressure on maximum demand.
- Long term (10-20 years) – maximum demand for Queensland is forecast to continue along the medium-term growth trajectory, driven largely by base and cooling load. Over this period, EV and battery charging activity is projected to pick up while rooftop PV generation declines, as the time of maximum demand transitions to early evening, around 18:00 to 20:00. As forecast PV generation growth declines and EV charging increases, batteries are projected to begin to discharge to the grid, resulting in a slight downward pressure on maximum demand that counteracts the strong growth in business and residential consumption.

Characteristics of maximum demand outcomes

The distribution of demand in Queensland is narrower than the other regions in summer, largely due to the relative size of LILs as a proportion of peak loads, along with the relatively more stable subtropical climate.

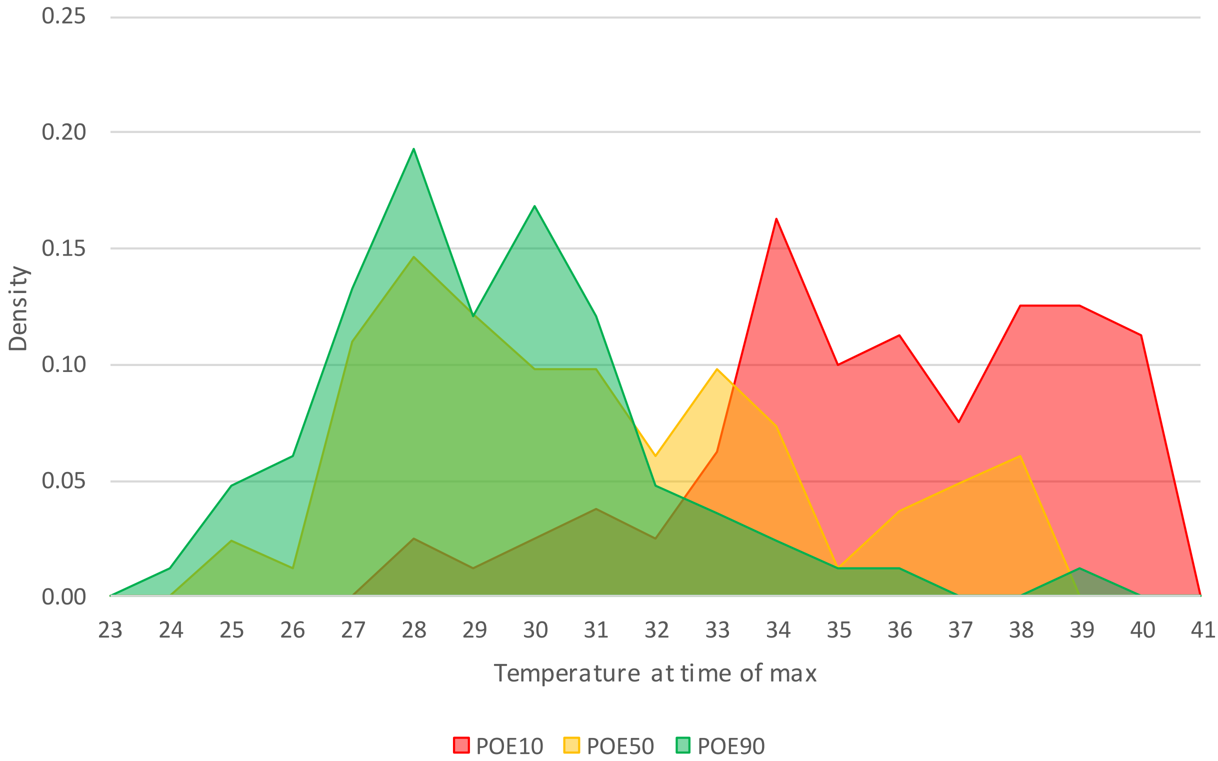
Queensland maximum operational demand is forecast to continue the trend of previous years, typically occurring between 15:00 and 19:00. Time of maximum demand is expected to be between 18:00 and 20:00 over the medium term, with a shift from late afternoon to early evening in the long term, as shown in Figure 42. This is consistent with the forecast of rapid uptake of rooftop PV generation in Queensland pushing maximum demand later into the day.

Figure 42 Distribution of forecast time of 50% POE summer maximum demand in Queensland



Queensland maximum operational demand is characterised by high temperatures and moderate humidity. The modelled 10% POE maximum demand mainly occurs when temperatures are between 32°C and 41°C, whereas 90% POE maximum demand events are clustered between 25°C and 32°C, as shown in Figure 43.

Figure 43 Distribution of temperature at time of forecast summer maximum demand in Queensland



A1.3 South Australia

Annual consumption outlook

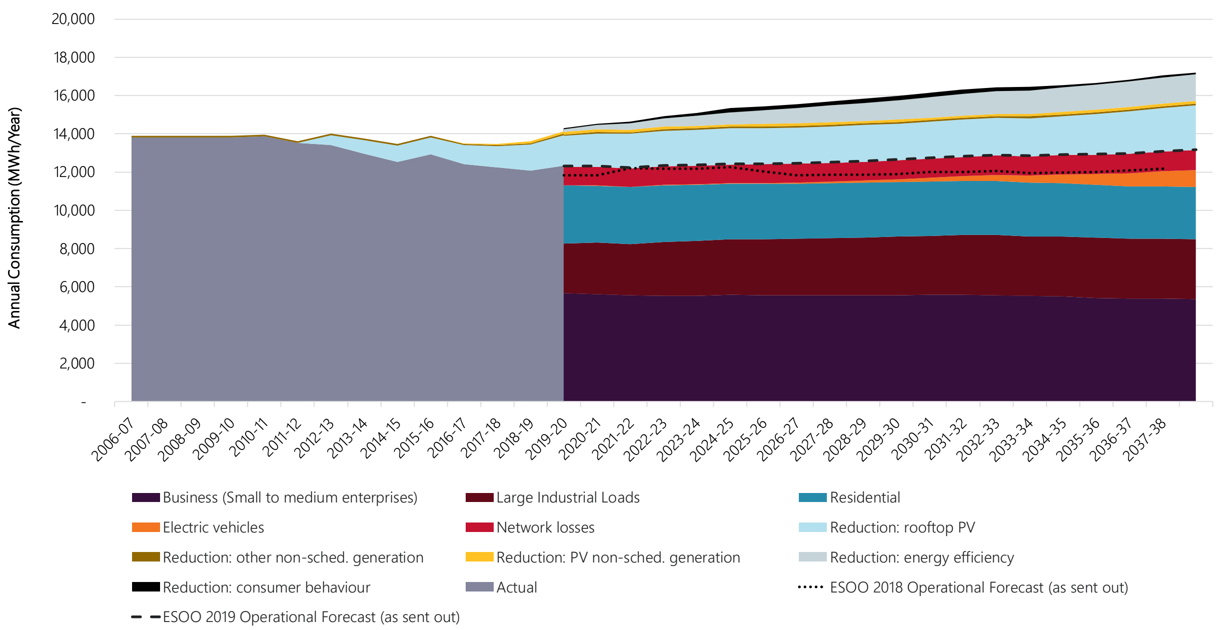
A key driver lowering forecast operational consumption in South Australia is the effect of additional EE savings beyond national measures provided by the South Australian REES, which is scheduled to end by 2020[99]. The REES requires energy retailers to provide discounted or free products and services to households and businesses to lower consumption.

The forecast can be examined across the short, medium, and long term as follows:

- In the short term (0-5 years) – a operational consumption is forecast to increase slightly from 12.1 TWh in 2018-19 to 12.4 TWh in 2024-25 (0.2% average annual growth rate).
- In the medium term (5-10 years) – operational consumption is forecast to increase from 12.4 TWh in 2024-25 to 12.5 TWh in 2028-29 (0.3% average annual growth rate).
- In the long term (10-20 years) – operational consumption is forecast to increase from 12.5 TWh in 2028-29 to 13.1 TWh in 2038-39 (0.5% average annual growth rate).

Figure 44 shows the component forecasts for the regional consumption in South Australia.

Figure 44 South Australia operational consumption in MWh, actual and forecast, 2006-07 to 2038-39



Maximum demand outlook

- Short term (0-5 years) – maximum operational demand is forecast to experience growth the first year, driven by growth in LIL, then to remain flat to 2023-24, resulting in 0.4% average annual growth in this period.
- Medium term (5-10 years) – maximum demand is forecast to grow by 0.1% from 2024-25 to 2028-29. Industrial loads are forecast to be broadly stable, but projected EV charging at time of maximum demand starts to pick up from 2024-25. The South Australian Government is providing 40,000 households with access to home battery systems, which is projected to have some dampening effect on grid demand during evening peaks.

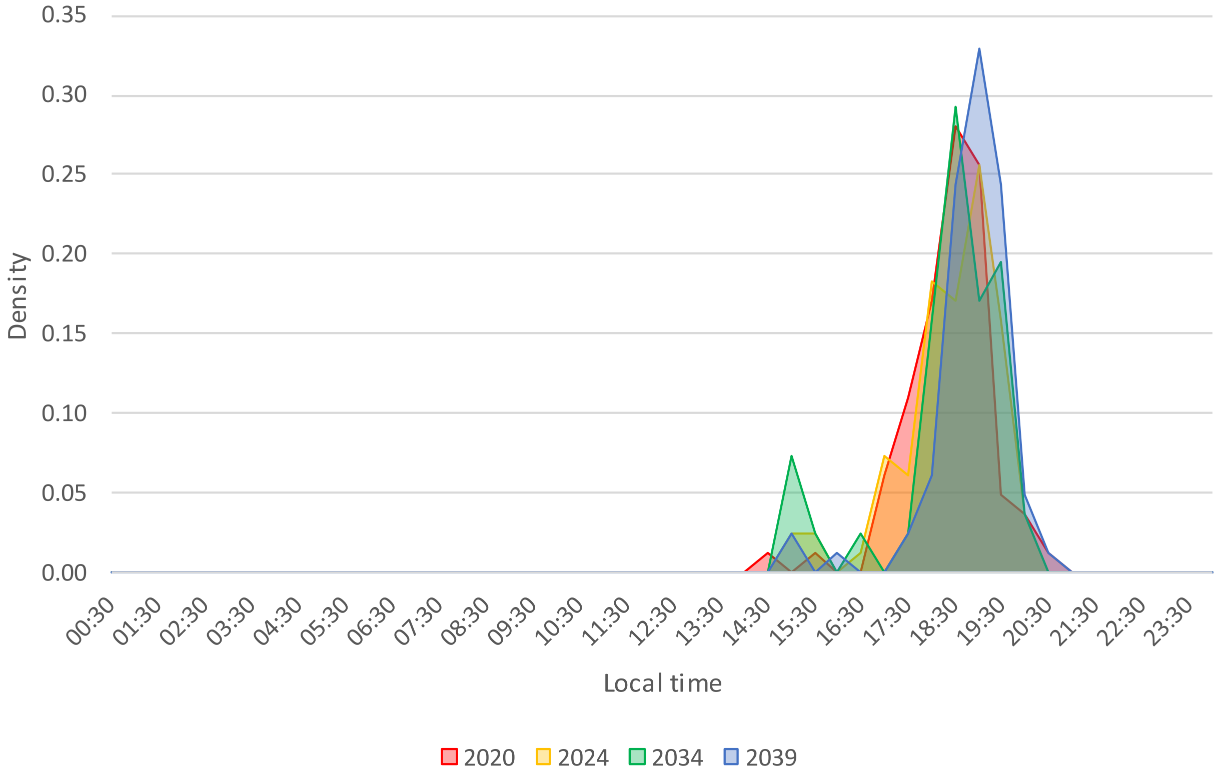
[99] A review of the REES is currently underway, regarding the possible extension of the scheme beyond the currently legislated end date of 2020.

- Long term (10-20 years) – maximum operational demand growth is forecast to continue (0.4% average annual growth), driven by accelerating growth in EVs and increased connections/population growth. Relative to the 2018 ESOO, forecast growth is broadly similar, due to higher EE for cooling load and lower EV charging at time of maximum demand offsetting growth in business and residential base load.

Characteristics of maximum demand outcomes

South Australia currently experiences maximum operational demand typically between 16:30 to 19:30 in the summer months. As maximum demand occurs later, the growth of rooftop PV and PVNSG is expected to continue to have little impact on maximum demand. The time of maximum operational demand is forecast to remain the same in the long term, as shown in Figure 45.

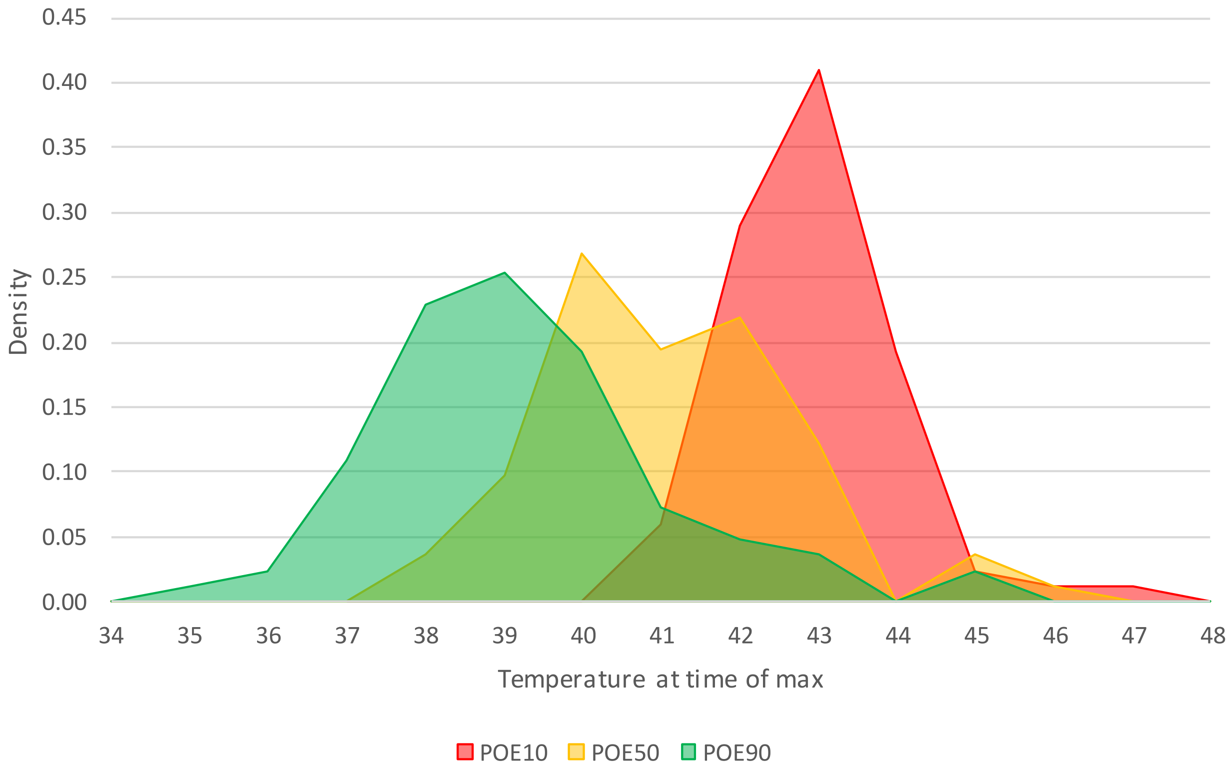
Figure 45 Distribution of forecast time of 50% POE summer maximum demand in South Australia



Maximum demand can occur due to a variety of conditions, high temperature, or heatwaves (daily rolling average of temperature) driving up demand, or low solar output. In South Australia, based on simulation outcomes, a 10% POE maximum demand can occur between 41°C to 45°C, a 50% POE between 38°C and 43°C, and a 90% POE between 36°C and 43°C, as shown in Figure 46.

PV generation at time of 10% POE is about the same as 50% POE, around 60 MW. This is largely governed by the expected time of day that maximum demand may fall.

Figure 46 Distribution of temperature at time of forecast summer maximum demand in South Australia



A1.4 Tasmania

Annual consumption outlook

The forecast operational consumption in Tasmania is relatively flat in the Central scenario, with a slight downward trend. The forecasts are lower in the 2019 Central forecast compared to the 2018 Neutral forecast, due to increased uptake of EE measures and revised EV forecasts.

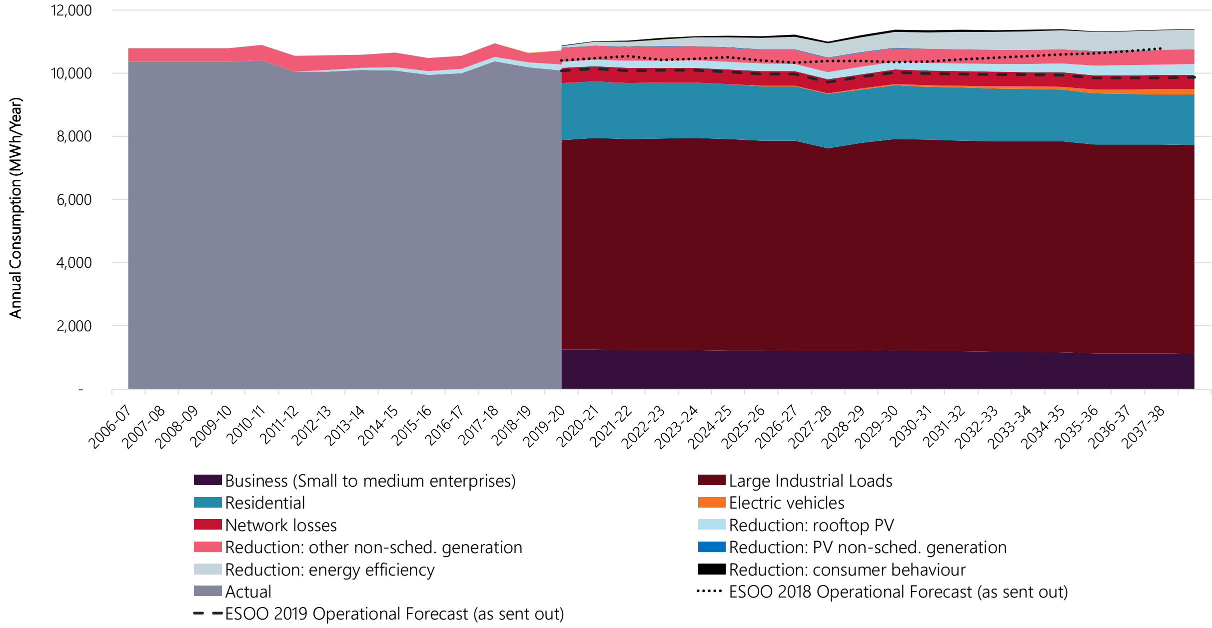
The forecast can be examined across the short, medium, and long term as follows:

- In the short term (0-5 years) – operational consumption is forecast to decrease slightly from 10.2 TWh in 2018-19 to 10.1 TWh in 2024-25 (-0.3% average annual growth rate).
- In the medium term (5-10 years) – operational consumption is forecast to decrease slightly from 10.1 TWh from 2024-25 to 10.0 TWh in 2028-29 (-0.4% average annual growth rate).
- In the long term (10-20 years) – operational consumption is forecast to stay flat, from 10.0 TWh in 2028-29 to 10.0 TWh in 2038-39 (-0.02% average annual growth rate – numbers are rounded).

Similar to the other NEM regions, forecast EV capacity in Tasmania has been revised downwards due to lower national vehicle sales projections and inclusion of ride share assumptions. Projected rooftop PV capacity is lower compared to the 2018 Neutral scenario across the entire horizon, but has a similar shape, with strong initial growth, then plateauing before picking up again from the early 2030s.

Figure 47 shows the component forecasts for regional consumption in Tasmania.

Figure 47 Total Tasmania operational consumption in MWh, actual and forecast, 2006-07 to 2038-39



Maximum demand outlook

Tasmania continues to experience its maximum operational demand in winter, with early morning peaks, as opposed to after sunset in the other NEM regions. This is in most part due to base and heating load, as well as LIL activity coinciding in the morning, coupled with a high proportion of EV charging and relatively low rooftop PV generation.

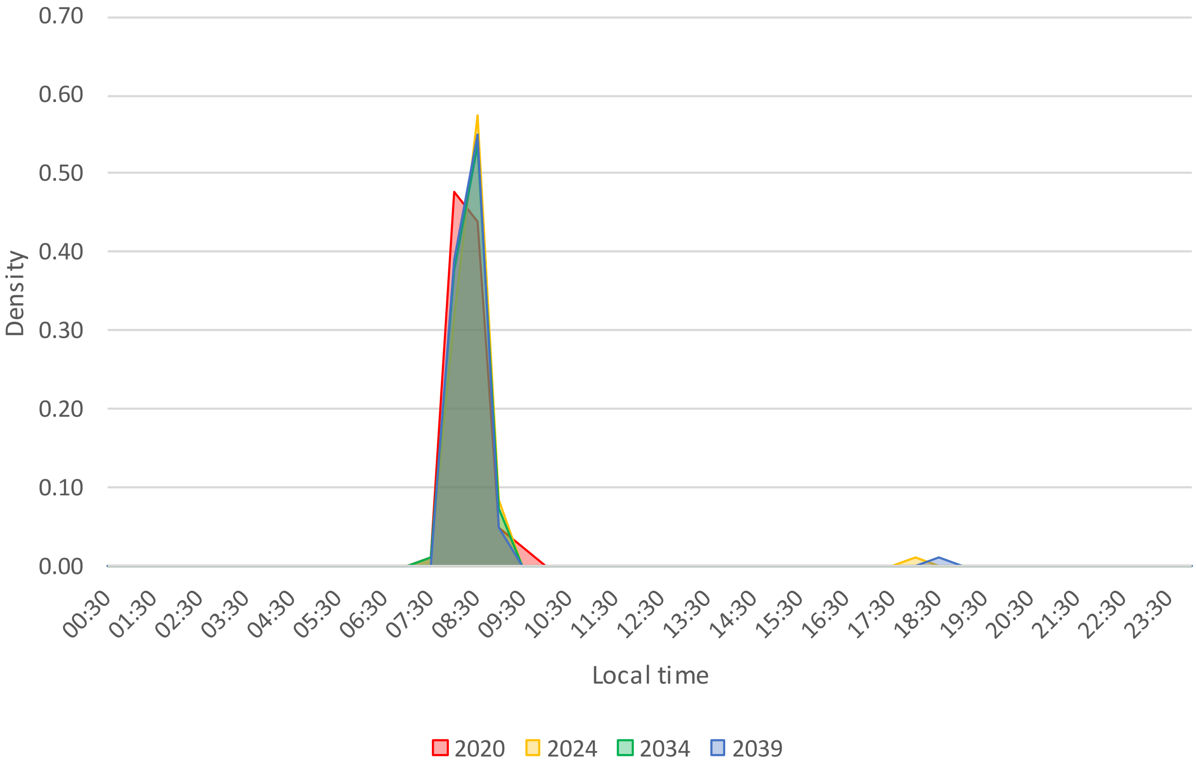
The maximum operating demand forecast in 2019 is higher than in the 2018 ESOO forecast, mainly due to stronger forecast business load growth.

- In the short term (0-5 years) – after initial projected growth in LIL, maximum demand in Tasmania is forecast to be relatively flat, resulting in a combined 0.1% annual average growth to 2023-24.
- In the medium term (5-10 years) – forecast maximum operational demand is flatter (-0.3% average annual growth from 2024-25 to 2028-29) but higher than in the 2018 ESOO forecast, due to slightly higher large industrial load that declines over the forecast period, as well as battery and EV charging activity. Overall, these drivers net to a slightly flatter trajectory for maximum operating demand, with a significant dip in 2027-28 due to a major load forecasting lower production during that year.
- In the long term (10-20 years) – LIL demand is forecast to continue to decline at a modest rate (-0.1% average annual growth), partly offset by projected growth in EV charging activity in the morning, as well as rooftop PV growth and battery charge. The 2019 ESOO forecast dips below the 2018 ESOO expectation around 2034-35, coinciding with a significant divergence in LIL and EV. While it is forecast that the overall fleet size for EVs is lower, there is a higher projected proportion of EV trucks, which are expected to charge in the mornings. Batteries are expected to charge in the mornings due to the growth of PV generation, as well as smarter charge profiles adopted for the 2019 ESOO.

Characteristics of maximum demand outcomes

Historically, Tasmanian maximum operational demand has occurred consistently in the early winter mornings around 8.00 to 9.00, typically on a Monday, where rooftop PV generation is low and heating load is peaking. The morning maximum demand trend is expected to continue throughout the forecast period, as shown in Figure 48. As a result of Tasmania's morning peak, EV and battery charging is projected to be higher at time of maximum demand, particularly as trucks are forecast to charge around this time.

Figure 48 Distribution of forecast time of 50% POE winter maximum demand in Tasmania

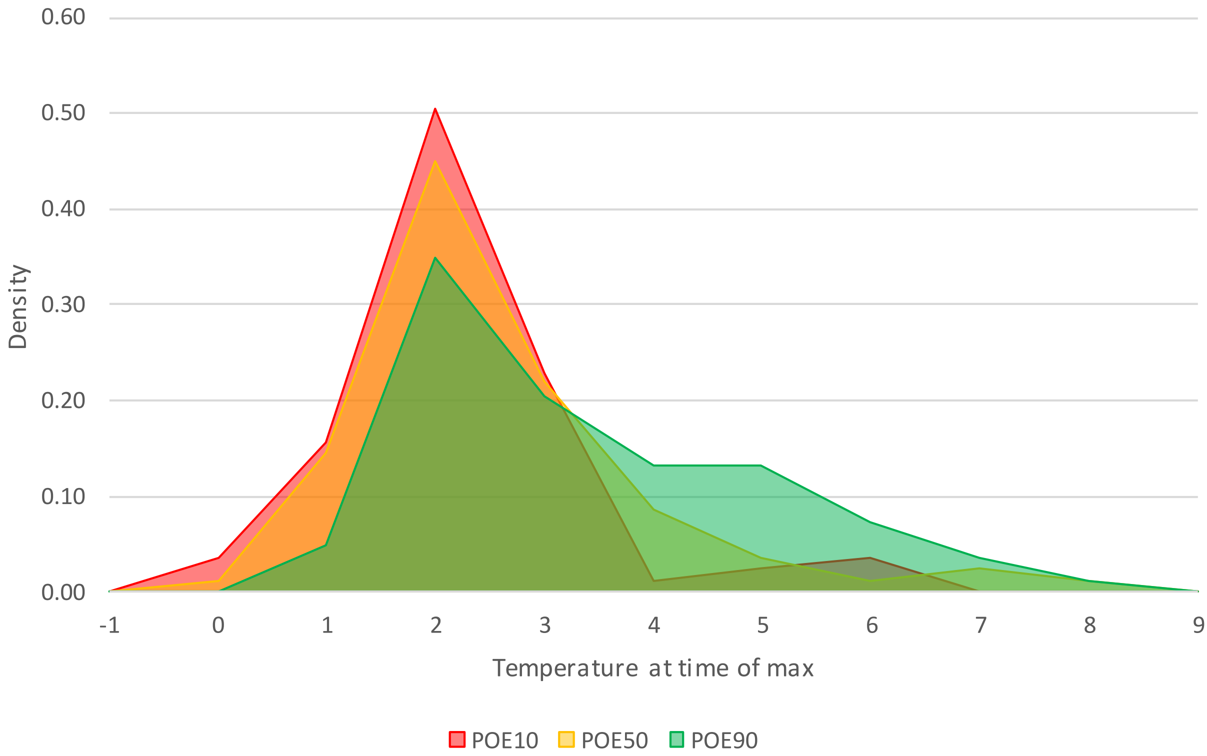


Tasmania has significantly different characteristics at time of maximum demand compared to other regions, being the only region to observe a winter maximum demand, driven largely by large industrial activity. As such, Tasmania is much less sensitive to weather effects like temperature, humidity, and solar irradiance.

Both 10% and 50% POE simulated events are closely distributed between 0°C and 4°C, whereas 90% POE events are between 1°C and 7°C, consistent with early winter mornings, as shown in Figure 49.

PV generation distributions for each POE type are all similar, with skew towards 0 and tails reaching around 30 MW, indicating that PV generation has very little appreciable impact on maximum demand.

Figure 49 Distribution of temperature at time of forecast winter maximum demand in Tasmania



A1.5 Victoria

Annual consumption outlook

The forecast operational consumption in Victoria is lower in the 2019 Central forecast compared to the 2018 Neutral forecast, due to forecast increased uptake of EE measures, continuing consideration of structural change affecting the business sector, and revised lower EV forecasts. Forecast rooftop PV capacity uptake is slower compared to the 2018 ESOO Neutral scenario, reflecting broad expectations that retail electricity prices will ease, although this has a moderate impact on the forecast compared to the other drivers.

In Victoria, EE is a key driver of the forecast decline in electricity consumption in the short to medium term for both business and residential sectors. The Victorian Energy Upgrades Program aims to reduce greenhouse gas emissions by providing access to discounted energy-efficient products and services, and is legislated to end in 2030. The program targets 6.5 Mt of carbon dioxide equivalent (CO2-e) reduction by 2020, although targets after 2020 have not yet been announced. AEMO has considered that other non-EE activities have a role in reducing emissions in the region in the future, and consequently has applied a 10% reduction per annum to the 2020 emission reduction target until the Program is legislated to end in 2030.

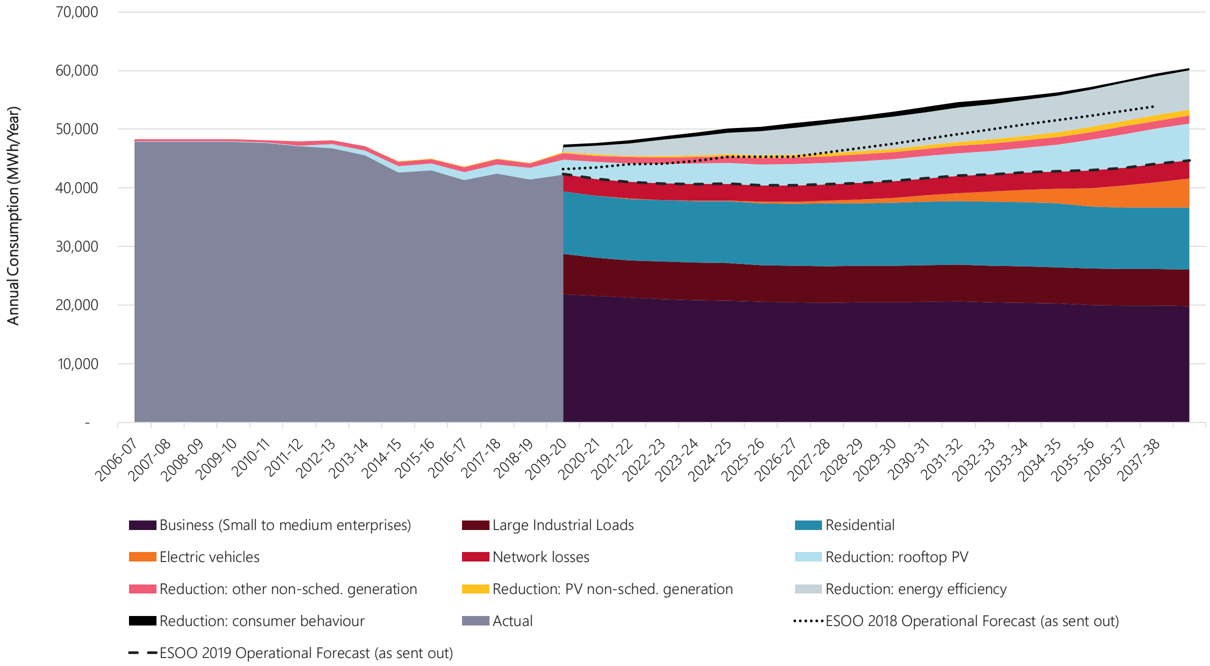
Over the long term, forecast business electricity consumption remains flat, due to continuing structural change and the increasing prevalence of businesses in the services sector in Victoria.

The forecast can be examined across the short, medium, and long term as follows:

- In the short term (0-5 years) – operational consumption is forecast to decrease from 41 TWh in 2018-19 to 41 TWh in 2024-25 (-0.6% average annual growth rate – numbers are rounded).
- In the medium term (5-10 years) – operational consumption is forecast to stay flat at 41 TWh from 2024-25 to 2028-29 (0.1% average annual growth rate).
- In the long term (10-20 years) – operational consumption is forecast to increase from 41 TWh in 2028-29 to 45 TWh in 2038-39 (0.9% average annual growth rate).

Figure 50 shows the component forecasts for regional consumption in Victoria.

Figure 50 Victoria operational consumption in MWh, actual and forecast, 2006-07 to 2038-39



Maximum demand outlook

Victoria's maximum operational demand is forecast to increase slightly in 2019-20, due to an increase in LIL expected in 2019-20. PV capacity is forecast to increase in 2019-20, but the level of PV capacity is forecast to be lower than what was forecast in the 2018 ESOO. This results in higher maximum demand (10% POE) for 2019-20 compared to what was forecast in the 2018 ESOO.

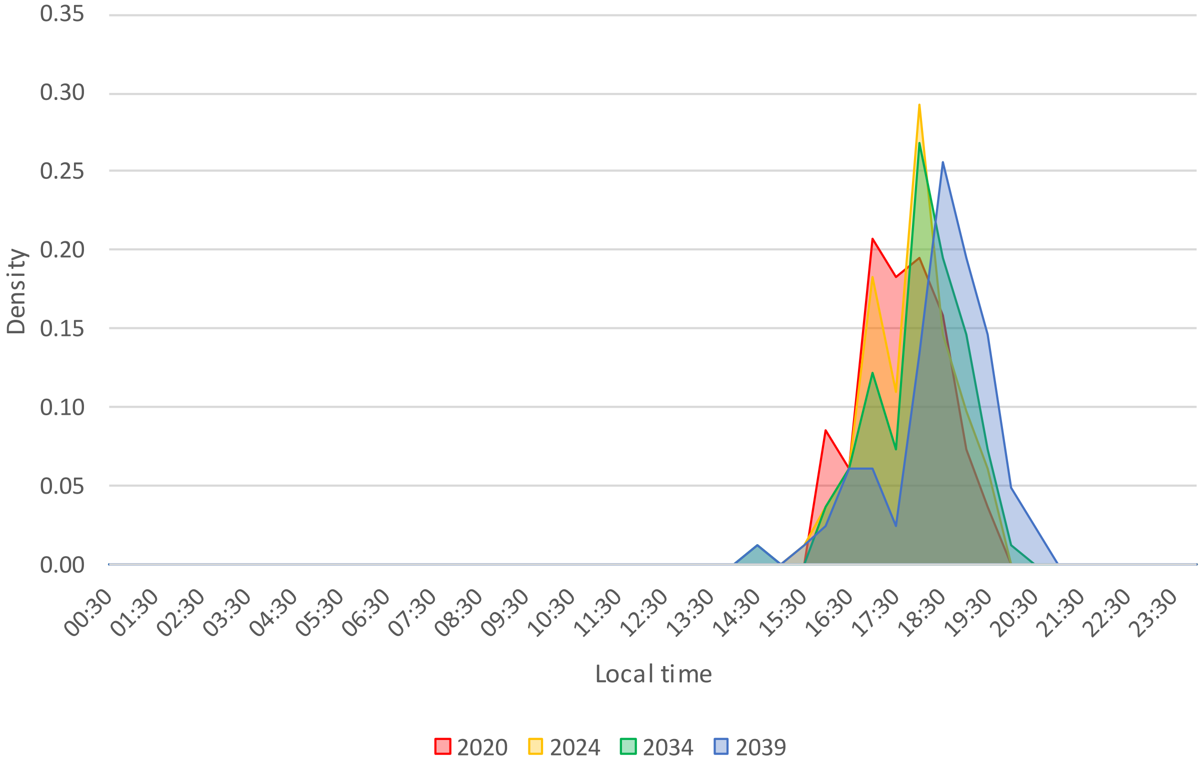
- In the short term (0-5 years) – after an initial projected increase in demand in the first year of the forecast, Victoria's maximum demand is forecast to decline, due to declining LIL and reduced business consumption driven by EE (-0.8% average annual growth to 2023-24).
- In the medium term (5-10 years) – Victoria's maximum operational demand is forecast to dip around 2024-25, due to declining business load in the business and LIL sectors, then grow towards 2028-29 as projected growth in residential load offsets declining business load, with a combined -0.1% average annual growth between 2024-25 and 2028-29. Compared to the 2018 ESOO forecast, growth over the next 10 years is flatter, largely due to the higher EE forecast.
- In the long term (10-20 years) – Victoria's forecast maximum operational demand shows growth (0.6% average annual growth) due to business and residential loads, as some EE schemes are expected to drop off. However, the growth is lower than the forecast growth in the 2018 ESOO over that horizon. Furthermore, EV charging 20 years out is forecast to be lower than in the 2018 ESOO, due to projections of slower uptake in EVs and a different EV charge profile that contributes less at time of peak demand.

Characteristics of maximum demand outcomes

Compared to the 2018 ESOO, this year's forecasts are not projected to approach sunset as quickly, due to lower forecast PV capacity.

Currently, Victoria's operational maximum demand is expected to occur between 16:00 and 19:00, which is expected to shift later in the day by an hour starting from 2038-39, as shown in Figure 51.

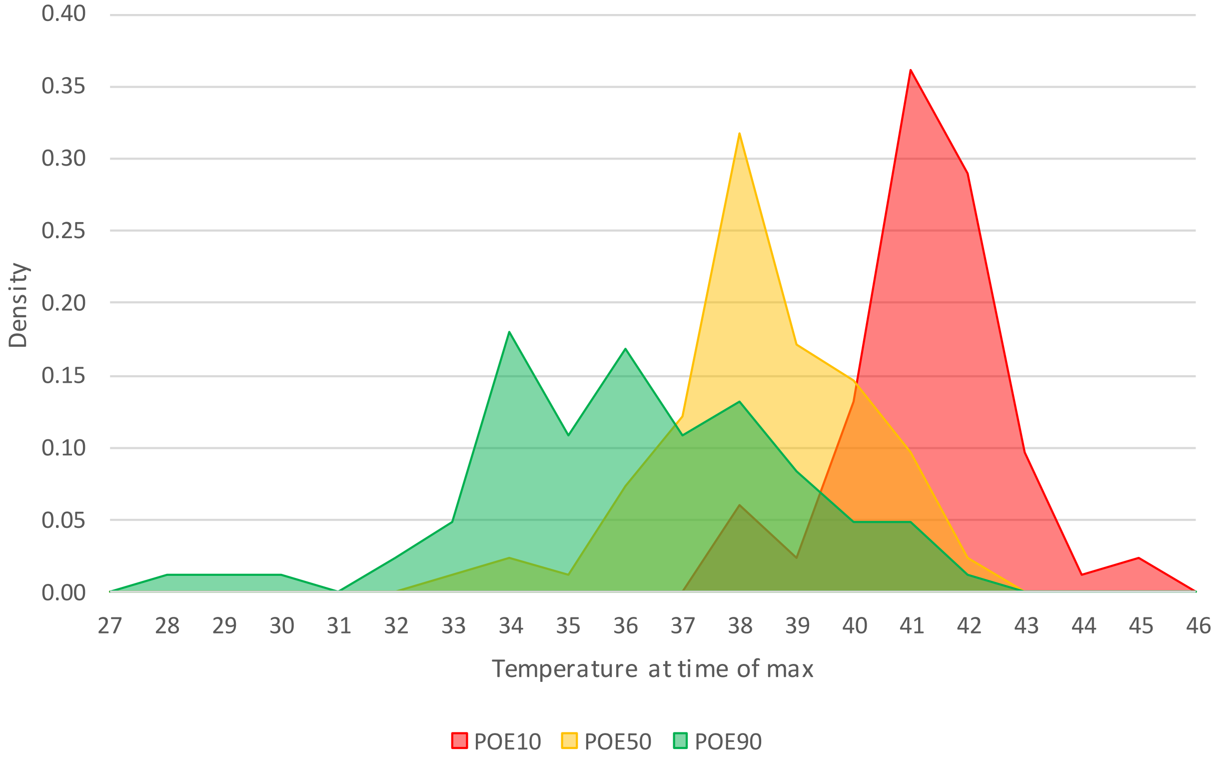
Figure 51 Distribution of forecast time of 50% POE summer maximum demand in Victoria



Maximum demand can occur due to conditions including high temperature, heatwaves (daily rolling average temperature), and low solar output. In Victoria, simulations indicate a 10% POE maximum demand typically occurs between 38°C to 45°C, 50% POE between 35°C and 43°C, and 90% POE between 31°C and 39°C, as shown in Figure 52.

PV generation at time of 10% POE is between 70 MW and 700 MW, whereas generation at time of 50% POE is around 150 MW to 1,000 MW. This is largely governed by the expected time of day maximum demand may occur.

Figure 52 Distribution of temperature at time of forecast summer maximum demand in Victoria



A2. Regional reliability outlook

This appendix provides further detail around forecast reliability for each NEM region. It includes an overview of the generation and storage changes and analysis of supply adequacy across the scenarios, and shows the projected reliability impact of the Group 1 transmission augmentations recommended in the 2018 ISP.

A2.1 New South Wales

Key insights

- The expected level of USE remains muted over the next three years, although there is the potential for load shedding, particularly under hot summer conditions.
- After the staggered closure of Liddell Power Station in 2022 and 2023, the level of USE in New South Wales is forecast to rise sharply to be only slightly below the reliability standard, reaching 0.00174% in 2023-24.
- Without additional investment, 375 MW of additional capacity would be required in 2023-24 to limit the risk of exceeding the existing reliability standard to below 10%.
- From 2023-24 onwards, the expected USE is very close to the reliability standard, and it is expected to be slightly above the standard in 2028-29 without any additional response.
- The introduction of Snowy 2.0 in March 2025 does little to improve reliability outcomes, as this modelling does not include the associated transmission needed to utilise the increase in firm capacity.
- Although the proposed ISP augmentations would help reduce expected USE outcomes when Liddell retires, 215 MW of additional strategic reserves would be required to reduce the risk of a major load shedding event to a one-in-10 year event.
- The New South Wales Government has already announced a number of programs that could help fill this gap, most notably the $75 million Emerging Energy, the $30 million Regional Community Energy, the $20 million Smart Batteries for Government Buildings, and the Empowering Homes programs.

A2.1.1 Generation and storage changes

There are currently 1,171 MW of committed large-scale solar projects in the region, in addition to a 100 MW upgrade to Bayswater Power Station, summarised in Table 20.

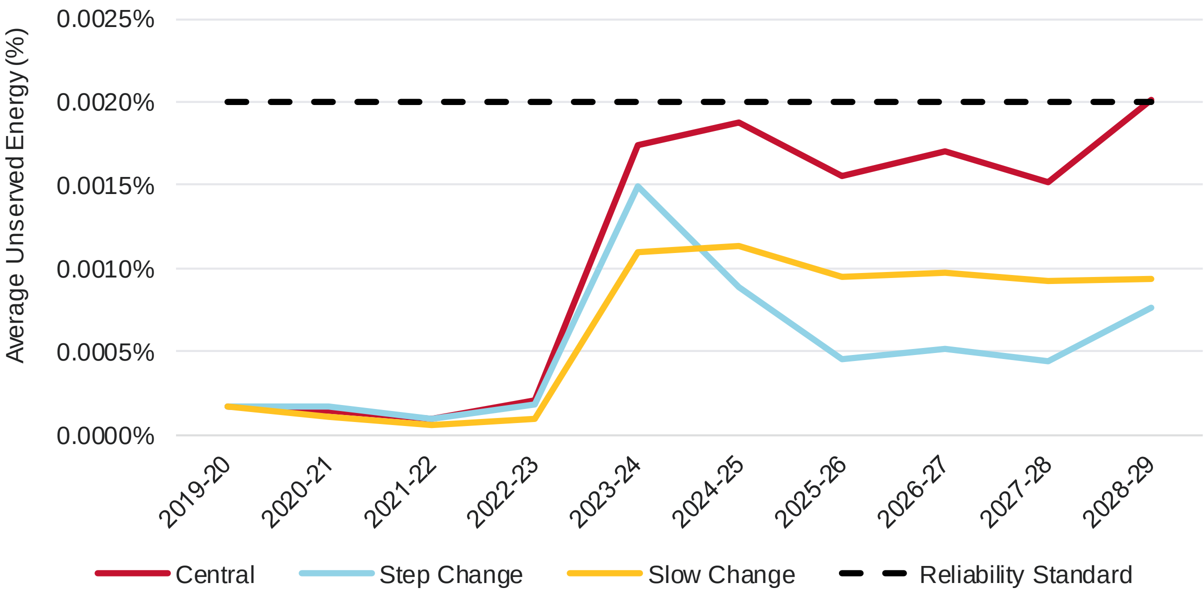
Table 20 New committed generation in New South Wales

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Bomen Solar Farm	121	Apr 2020
	Darlington Point Solar Farm	275	Dec 2019
	Finley Solar Farm	162	Oct 2019
	Limondale Solar Farm 1	220	May 2020
	Limondale Solar Farm 2	29	Dec 2019
	Molong Solar Farm	30	Jun 2020
	Nevertire Solar Farm	105	Jul 2019
	Sunraysia Solar Farm	229	Oct 2019
Generator upgrades	Bayswater Power Station	100	2019-2022

A2.1.2 Supply adequacy assessment

Figure 53 below shows the projected level of USE for the Step Change, Slow Change, and Central scenarios. These scenarios assume only committed generators enter the market over the ESOO timeframe.

Figure 53 Forecast USE outcomes, New South Wales



In the Central scenario, the forecast risk of USE increases after the retirement of Liddell Power Station in 2023 and remains close to the current reliability standard from that point onwards. Without further development, the reliability standard is forecast not to be met in the Central scenario in 2028-29.

In the Step Change scenario, USE rises with the retirement of Liddell but remains slightly below the Central scenario. Beyond this point the expected USE progressively reduces, due to more VPPs being projected to come online, driven by assumed strong business cases from existing trials. VPPs act to reduce the peak demand that is met by large-scale generation.

In the Slow Change scenario, expected USE is below the Central scenario due to lower maximum demand growth compared to the Central scenario, driven by lower economic activity and population growth.

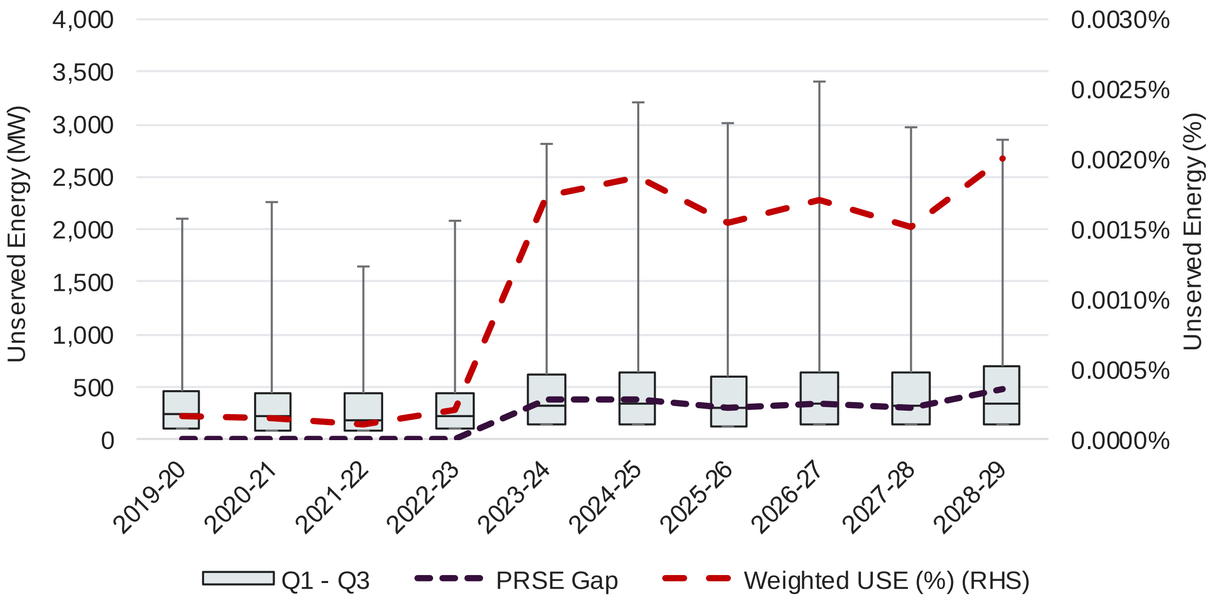
The forecast size of USE events is shown in Figure 54, noting that over the first four years the number of USE events from which these distributions are based is very small. The 'box and whisker' plots show the magnitude of USE that has occurred in the market simulations. The figure shows for each year, the maximum, minimum, median, first, and third quartiles of USE across all simulations.

This figure shows that in 2023-24, for example, 75% of observed USE events are below 620 MW. The size of USE events remains relatively constant over the remaining horizon. Over the large number of simulations run, the maximum observed USE tends to be very large, which is attributable to an unfortunate combination of generation outages occurring at the time of peak demand.

Over the next three years, the size of USE events is forecast to remain similar, with some risk of high levels of load shedding. However, given the relatively low expected USE, the frequency of these events is low.

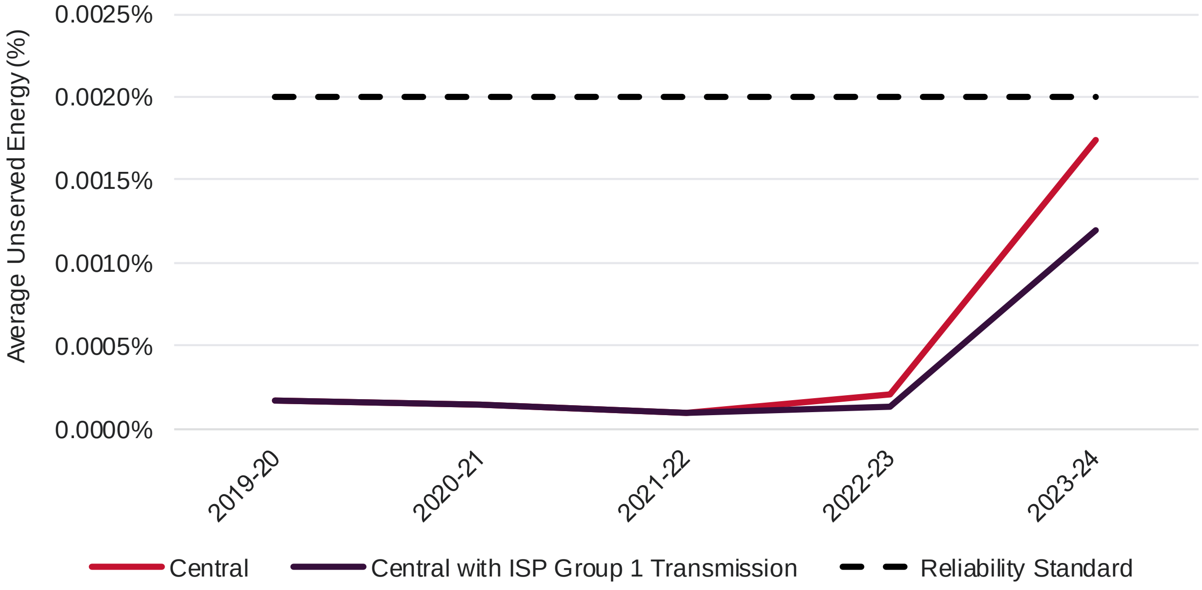
The figure also shows the additional megawatts required to limit the probability of reliability standard exceedance (PRSE) to 10%. After the retirement of Liddell, this requirement is between 300 MW and 480 MW and is similar to the median size of USE events.

Figure 54 Forecast size of USE events, New South Wales, Central, (10 POE demand USE events)



The ISP Group 1 Transmission sensitivity involved minor augmentations to both the QNI and VNI interconnectors which link New South Wales with Queensland and Victoria respectively. These augmentations (which are assumed to occur in 2022 in the ESOO analysis) help offset some of the impact of the retirement of Liddell by unlocking additional interconnector support from Queensland and Victoria. The impact of the ISP Group 1 transmission projects on USE in the first five years is shown in Figure 55 below.

Figure 55 Forecast USE outcomes, New South Wales, impact of ISP Group 1 Transmission



A2.2 Queensland

Key insights

The 2019 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. While USE levels are small, there is some risk of USE under extreme conditions (higher than in the 2018 ESOO), due to increases in the maximum demand forecasts in the region.
- The augmentation of the QNI interconnector between Queensland and New South Wales modelled in the ISP sensitivity utilises surplus generation in Queensland to reduce the risk of load shedding in New South Wales.

A2.2.1 Generation and storage changes

There are 1,109 MW of committed large-scale wind and solar generation projects in Queensland, listed in Table 21.

Table 21 New committed generation in Queensland

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Haughton Solar Farm Stage 1	133	Sep 2019
	Hughenden Sun Farm	18	Jul 2019
	Kennedy Energy Park- Phase 1- Solar	15	Aug 2019*
	Lilyvale Solar Farm	100	Sep 2019
	Oakey 2 Solar Farm	56	Oct 2019
	Maryborough Solar Farm	35	Mar 2020

	Project	Capacity (MW)	Commercial operation date
	Oakey Solar Farm	25	Aug 2019
	Rugby Run Solar Farm	65	Nov 2019
	Warwick Solar Farm	64	Jun 2020
	Yarranlea Solar Farm	103	Nov 2019
Large-scale wind	Coopers Gap Wind Farm	453	Apr 2020
	Kennedy Energy Park- Phase 1- Wind	43	Aug 2019*

*This commercial operation date has been delayed until 1 July 2021 due to project status.

A2.3 South Australia

Key insights

The 2019 ESOO projects:

- The expected level of USE for next summer is relatively low in South Australia.
- As the Torrens Island A Power Station (480 MW) completes its withdrawal, the level of expected USE rises, to 0.0004% in 2021-22. The withdrawal of Torrens A is partially offset by the introduction of the Barker Inlet Power Station (210 MW) in 2019.
- In 2023-24 ,the expected level of USE increases to 0.0011% following the decommissioning of Osborne Power Station (172 MW).
- Although expected USE remains below the current standard from 2023-24, additional strategic reserves would be required to reduce the risk of a major load shedding event to a one-in-10 year event.
- The Group 1 transmission projects identified in the 2018 ISP would improve reliability in South Australia, due to the additional capability to transfer power from New South Wales to Victoria (and subsequently through to South Australia) provided by the minor VNI augmentation.
- This analysis does not consider the introduction of the proposed EnergyConnect interconnector between South Australia and New South Wales currently under review by the AER, which could help to offset the impact of Osborne Power Station's retirement.

A2.3.1 Generation and storage changes

There are 221 MW of committed large-scale wind and solar generation projects in South Australia, 10 MW of committed large-scale battery storage, and 210 MW of committed natural gas-fired generation, as listed in Table 22.

The 2019 ESOO also includes the staged withdrawal of Torrens Island A (480 MW), which will commence mothballing in 2020, with two units reducing their available capacity to 0 MW in late 2019, and the other two units in 2020 and 2021. The retirement of Osborne Power Station (172 MW summer capacity) on 1 January 2024 is also included in the modelling. Snowtown Wind Farm (99 MW capacity) is also expected to close towards the end of the modelling horizon, in 2028-29.

Table 22 New committed generation and storage in South Australia

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Bungala Two Solar Farm	135	Mar 2020
Large-scale wind	Lincoln Gap Wind Farm – stage 2	86	May 2020
Battery storage	Lincoln Gap Battery Energy Storage System (BESS)	10 MW/10 MWh	Apr 2019
Natural gas	Barker Inlet Power Station	210	Nov 2019
Generator upgrades	Quarantine Power Station	24	2020 - 2023

A2.3.2 Supply adequacy assessment

Figure 56 below shows the projected level of USE for the Step Change, Slow Change, and Central scenarios. These scenarios assume only committed generators enter the market over the ESOO timeframe.

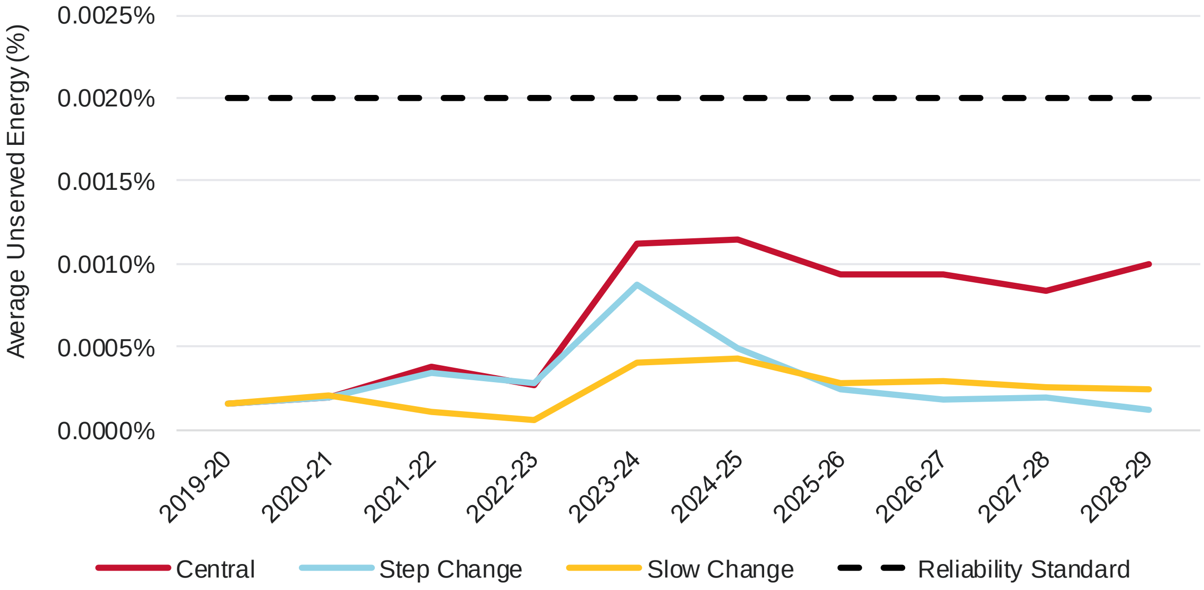
USE risks remain relatively low over the first four years in all scenarios, but rise slightly due to the retirement of the Torrens Island Power Station (480 MW) which is only partially offset by the new capacity provided at Barker Inlet Power Station (210 MW).

After the decommissioning of Osborne (172 MW), expected USE rises in all scenarios in 2023-24. USE remains below the current reliability standard throughout the ESOO horizon in all scenarios, but the risk of significant load shedding remains high.

The level of USE risk in the Step Change scenario remains below the Central scenario and reduces from 2023-24, due to an increasing amount of VPPs coming online driven by strong business cases from existing trials assumed in the Step Change scenario.

In the Slow Change scenario, expected USE remains low, due to forecast low maximum demand growth driven by lower economic activity and population growth compared to other scenarios.

Figure 56 Forecast USE outcomes, South Australia

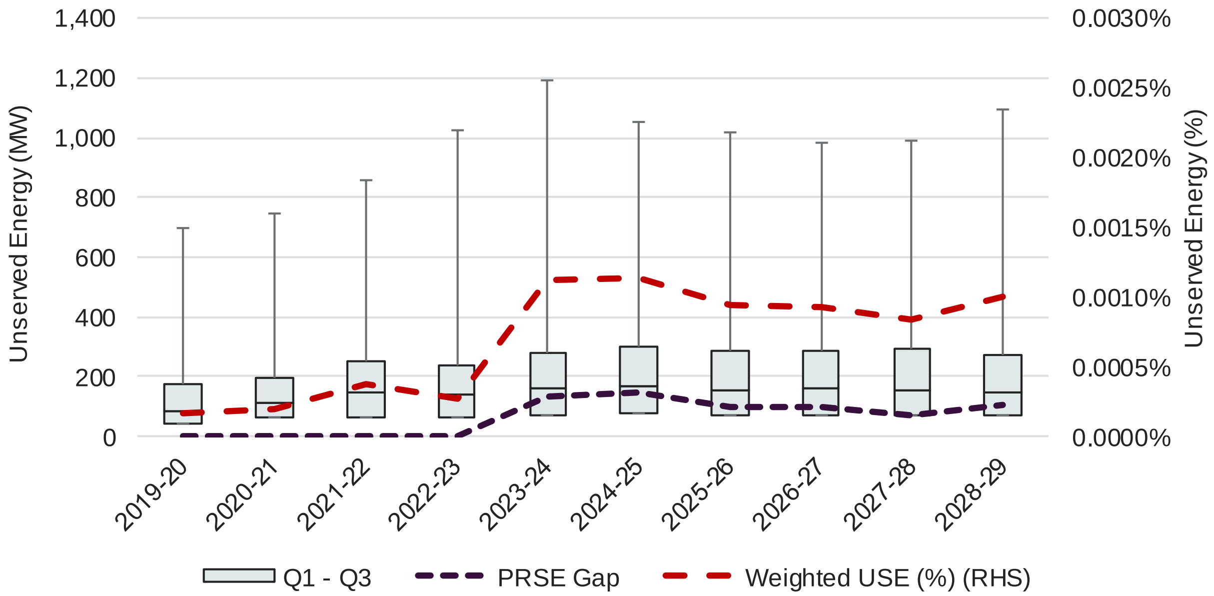


The forecast size of USE events is shown in Figure 57, noting that over the first four years the number of USE events from which these distributions are based is very small. The ‘box and whisker’ plots show the magnitude of USE that has occurred in the market simulations. The figure shows for each year, the maximum, minimum, median, first, and third quartiles of USE across all simulations.

This figure shows that in 2023-24, for example, 75% of observed USE events are below 279 MW. The size of USE events remains relatively constant over the entire modelling horizon, though the expected USE and the likelihood of USE increases from 2023-24. Over the large number of simulations run, the maximum observed USE tends to be very large, which is attributable to an unfortunate combination of generation outages occurring at the time of peak demand.

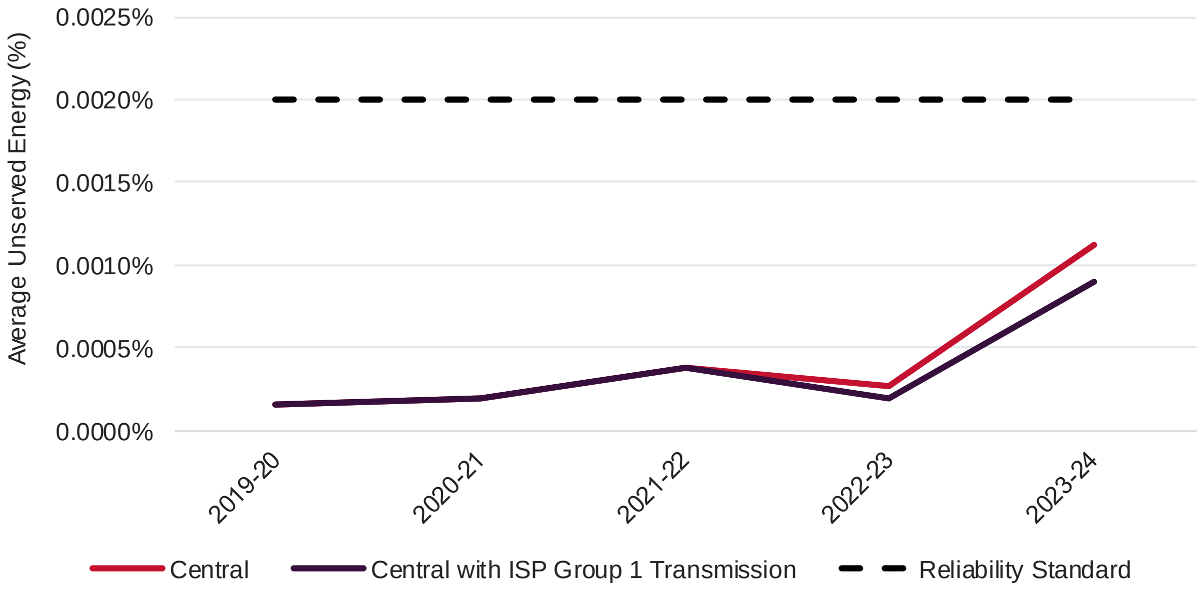
As with New South Wales, the firm megawatts of additional capacity required to limit the probability of exceeding the current reliability standard to 10% (PRSE gap) is roughly equivalent to the median size of USE events in years when the expected USE is highest.

Figure 57 Forecast size of USE events, South Australia, Central, (10 POE demand USE events)



Although none of the transmission augmentations implemented in the ISP Group 1 sensitivity directly impact South Australia, the additional transmission investment does reduce USE slightly. This is due to an increase the capability of Victoria to export into South Australia that occurs as a result of the minor VNI augmentation. The USE outcomes under the ISP sensitivity are shown in Figure 58 below.

Figure 58 Forecast USE outcomes, South Australia, impact of ISP Group 1 Transmission



A2.4 Tasmania

Key insights

The 2019 ESOO projects no USE in any scenario in Tasmania, which has a significant surplus in generation capacity, although this is limited at times due to reservoir storage levels. The resilience of Tasmanian electricity supply to rainfall conditions is analysed in AEMO's Energy Adequacy Assessment Projection (EAAP).

A2.4.1 Generation and storage changes

There are 265 MW of committed large-scale wind projects that have met AEMO's commitment criteria in Tasmania, as listed in Table 23.

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

Table 23 New committed generation and storage in Tasmania

	Project	Capacity (MW)	Commercial operation date
Large-scale wind	Granville Harbour Wind Farm	112	Apr 2020
	Cattle Wind Farm	154	Jan 2020

A2.5 Victoria

Key insights

- Currently there are two major units in Victoria that provide over 750 MW of capacity that are unavailable due to long-term outages and are not scheduled to return until mid-December.
- Based on the expected probabilities of these being delayed in return to service, the expected level of USE (0.0026%) exceeds the reliability standard.
- AEMO forecasts that approximately 125 MW of additional firm reserves would be required to meet the reliability standard this summer. Even if this 125 MW were made available, the expected amount of USE would be the equivalent of approximately 435,000 households without power in Victoria for an hour.
- USE is expected to decrease in Victoria after 2019-20 with the return to service of the power stations currently on outages, an increase in renewable generation, and a forecast reduction in expected peak demand, as well as minor generation upgrades. The forecast does not consider the possibility that the reliability of aging generators will continue to deteriorate, and may not fully capture the likelihood of the types of long-term outages currently occurring.
- A number of Victorian Government initiatives are expected to further mitigate the reliability issues. For example, the VRET is expected to induce additional generation capacity and the Battery Storage Initiative will increase installed storage capacity.
- The proposed ISP Group 1 transmission augmentations would help further improve reliability in Victoria by allowing additional import capacity from New South Wales.

A2.5.1 Generation and storage changes

There are 2,003 MW of committed large-scale wind and solar projects and 20 MW of large-scale battery storage projects in Victoria, summarised in Table 24.

Table 24 New committed generation and storage in Victoria

	Project	Capacity (MW)	Commercial operation date
Large-scale solar	Cohuna Solar Farm	31	Nov 2019*
	Kiamal Solar Farm stage 1	200	Oct 2019*
	Yatpool Solar Farm	94	Nov 2019
Large-scale wind	Bulgana Green Power Hub – Wind Farm	204	Aug 2019
	Cherry Tree Wind Farm	58	Jun 2020
	Dundonnell Wind Farm	336	Jul 2020
	Lal Lal Wind Farm Elaine	84	Jul 2019
	Lal Lal Wind Farm Yendon	144	Jul 2019
	Moorabool Wind Farm	320	Jun 2020
	Stockyard Hill Wind Farm	532	May 2020
Battery storage	Bulgana Green Power Hub – Battery Energy Storage System (BESS)	20 MW/34 MWh	Aug 2019

	Project	Capacity (MW)	Commercial operation date
Generator upgrades	Loy Yang A Power Station	15	Dec 2020
	Loy Yang B Power Station	80	Apr 2020
	Mortlake Power Station *Capacity increase to summer rating only*	40	Nov 2020

* This commercial operation date has been delayed until 1 July 2021 in AEMO's modelling, due to project status.

A2.5.2 Supply adequacy assessment

Figure 59 below shows the projected level of USE for the Step Change, Slow Change, and Central scenarios. These scenarios assume only committed generators enter the market over the ESOO timeframe.

USE risks are projected to be high in 2019-20, if no additional reserves are procured. Chapter 5 provides a detailed analysis of the drivers of the reliability risk for this summer.

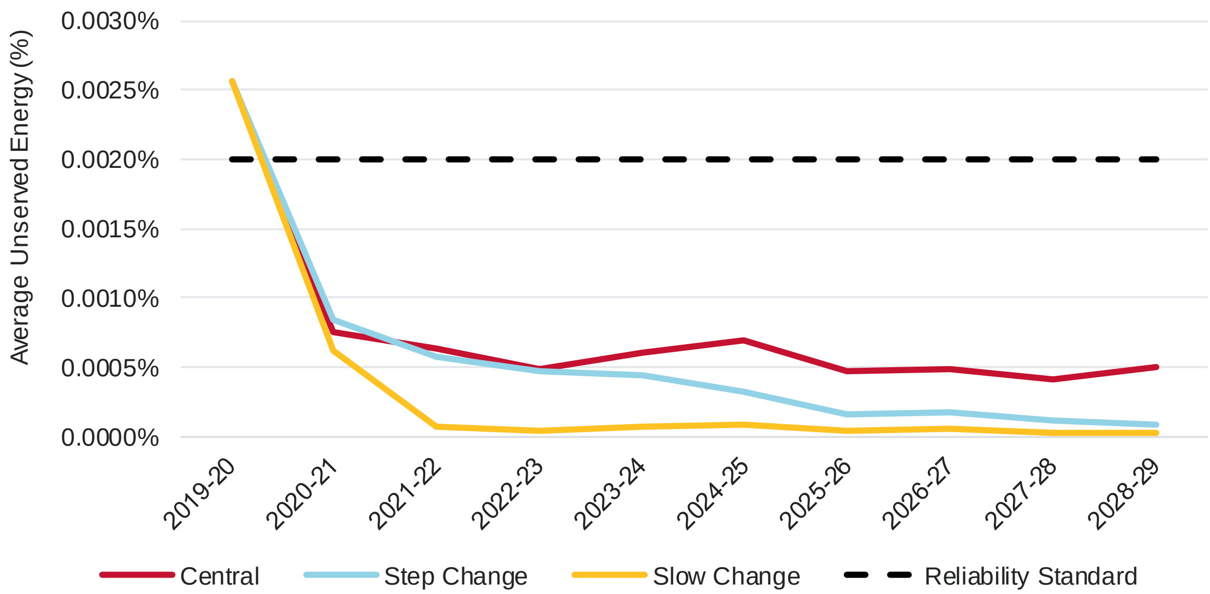
The level of forecast USE declines following this summer, and remains muted throughout the ESOO horizon. The decline is due to a combination of factors, including the return to service of generators currently on outage, the projected impact of additional renewable generation, and reduction in forecast maximum demand.

Although the impact of the current long-term outages does not affect the forecast beyond this summer, based on recent history there is a chance that similar events could occur at other units as the generation fleet ages. The forecast does not necessarily fully account for these rare events, particularly where the events are the result of force majeure. Nor does the forecast consider the possibility of deteriorating plant reliability. AEMO will continue to monitor the reliability of generation and will incorporate this information into future reliability forecasts.

The level of USE in the Step Change scenario decreases below the Central scenario from 2023-24 due to an increasing amount of VPPs assumed coming online driven by strong business cases from existing trials.

In the Slow Change scenario, expected USE remains low, due to low forecast maximum demand growth driven by lower economic activity and population growth compared to other scenarios.

Figure 59 Forecast USE outcomes, Victoria

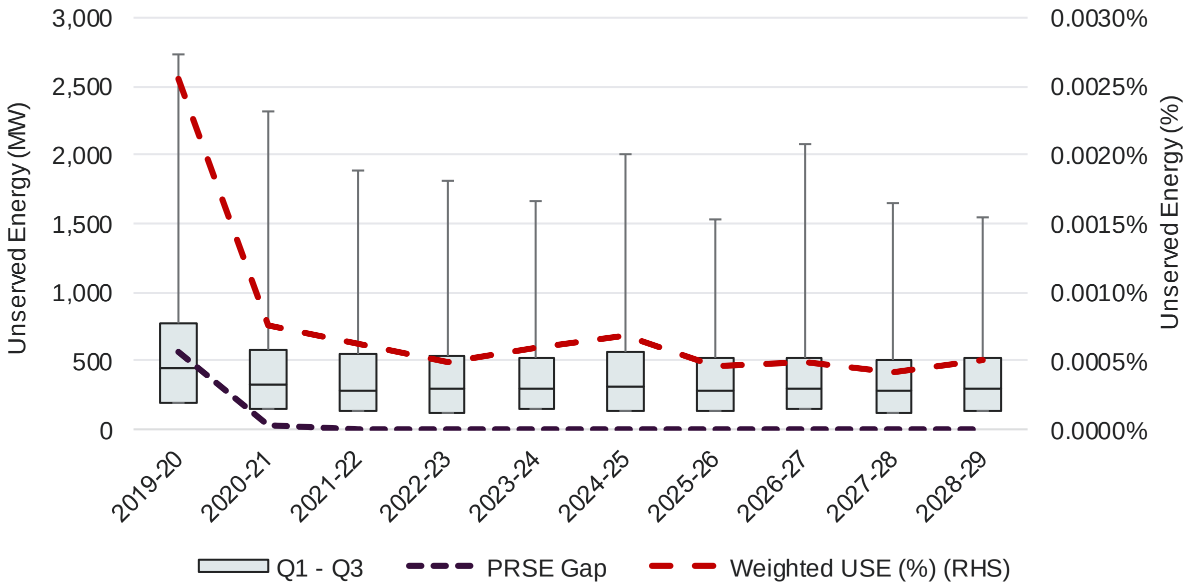


The forecast size of USE events is shown in Figure 60. The 'box and whisker' plots show the magnitude of USE that has occurred in the market simulations. The figure shows for each year, the maximum, minimum, median, first, and third quartiles of USE across all simulations.

This figure shows that in 2019-20, for example, 75% of observed USE events are below 773 MW. After this summer, the size of USE events reduces as the reliability outlook improves. Over the large number of simulations run, the maximum observed USE tends to be very large, which is attributable to an unfortunate combination of generation outages occurring at the time of peak demand.

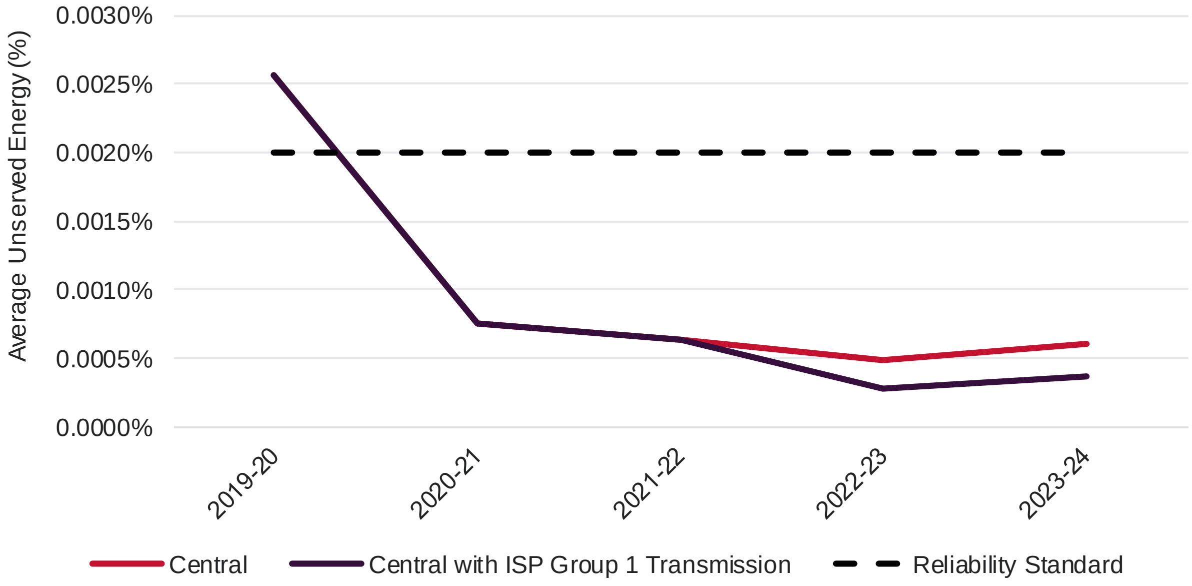
The additional megawatts required to reduce the risk of reliability in excess of the reliability standard to below 10% (PRSE gap) is above the median USE event observed this summer. The level of additional capacity required reflects the risk of large load shedding events, particularly if neither the Mortlake or Loy Yang units return to service for the key summer months.

Figure 60 Forecast size of USE events, Victoria, Central, (10 POE demand USE events)



The ISP Group 1 Transmission sensitivity included augmentations to the transmission system, with the augmentation of VNI of most relevance to Victoria. The introduction of this augmentation reduces USE in both Victoria and South Australia by increasing the ability to import from New South Wales. Figure 61 shows the impact of the ISP Group 1 transmission augmentation on expected USE in the Central scenario.

Figure 61 Forecast USE outcomes, Victoria, impact of ISP Group 1 Transmission



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
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BoM	Bureau of Meteorology
CBD	Commercial Building Disclosure
CCGT	Closed-cycle gas turbine
CER	Clean Energy Regulator
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DSP	Demand side participation
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection

Abbreviation	Full name
EE	Energy efficiency
EFI	Electricity Forecasting Insights
ESB	Energy Security Board
ESS	New South Wales Energy Savings Scheme
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FRG	Forecasting Reference Group
GEMS	Greenhouse and Energy Minimum Standards program
GSP	Gross State Product
HIA	Housing Industry Association
ISP	Integrated System Plan
LOLP	Loss of Load Probability
MT PASA	Medium Term Projected Assessment of System Adequacy
MTTR	Mean time to repair
NABERS	National Australian Built Environment Rating System
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
PRSE	Probability of reliability standard exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland New South Wales Interconnector
RCP	Representative Concentration Pathway
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
RRO	Retailer Reliability Obligation
STC	Small-scale Technology Certificate
USE	Unserved energy
VNI	Victoria New South Wales Interconnector
VPP	Virtual power plant
VRET	Victorian Renewable Energy Target

Glossary

Term	Definition
committed and 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. Commitment criteria are outlined 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.
reliability standard	The reliability standard for generation and inter-regional transmission elements in the NEM is defined in NER 3.9.3C as a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
unserved energy	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). The USE that contributes to the reliability standard excludes unserved energy resulting from multiple or non-credible generation and transmission events, network outages not associated with inter regional flows, or industrial action (NER 3.9.3C(b)).