



2021 Electricity Statement of Opportunities

August 2021

A report for the National Electricity Market

Important notice

PURPOSE

The purpose of this publication is to provide technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the National Electricity Market over a 10-year outlook period. This publication incorporates a reliability assessment against the reliability standard and interim reliability measure, including AEMO's reliability forecasts and indicative reliability forecasts.

AEMO publishes the National Electricity Market Electricity Statement of Opportunities in accordance with clause 3.13.3A of the National Electricity Rules.

This publication is generally based on information available to AEMO as at 1 July 2021 unless otherwise indicated.

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ACKNOWLEDGEMENT

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Executive summary

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data for the National Electricity Market (NEM) over a 10-year period to inform the planning and decision-making of market participants, new investors, and jurisdictional bodies. The ESOO includes a reliability forecast identifying any forecast reliability gaps in the coming five years, defined according to the Retailer Reliability Obligation (RRO)¹, and an indicative projection of any forecast reliability gaps in the second five years of the forecast.

A key focus of this year's ESOO is on managing an accelerating transition towards high instantaneous penetration of renewable generation, thermal generation withdrawal, and 'green' hydrogen consumption.

Continued rapid development of new large-scale and distributed renewable resources and dispatchable firming capacity (battery storage and gas generation) has helped improve the reliability outlook for summer 2021-22 and the first five years of the outlook. Existing and committed future electricity supply is projected to be adequate to support forecast demand under most conditions prior to the expected closure of Victoria's Yallourn Power Station in 2028, although the power system is also becoming more exposed to extreme weather events that could lead to supply scarcity.

Multiple interrelated drivers are accelerating the energy transition in the NEM and making the management of system reliability and security more complex:

- **Accelerated deployment of large-scale and distributed renewable resources** – total existing and committed large-scale solar and wind capacity, and distributed photovoltaics (PV) installed behind the meter by businesses and households, is forecast to be 12 gigawatts (GW) higher in 2025 than today. At current rates of large-scale wind and solar development, there could be sufficient renewable resources available in 2025 to meet 100% of underlying consumer demand in certain periods. Further, the growth in distributed PV continues to meet more daytime consumer demand, driving down minimum demand from the grid even faster than projected last year. By 2025, working closely with industry stakeholders, AEMO has the goal to engineer the power system to be capable of operating securely through these periods of high instantaneous penetration of renewable energy.
- **Accelerated exit of coal and increasing risk of plant failures** – since the 2020 ESOO, the planned retirements of Yallourn Power Station (Victoria) and two units of Eraring Power Station (New South Wales) have been brought forward. Coal-fired generation reliability remained at historically poor levels last year. While some plant improvements are expected in the near term, most generators are anticipating a trend of decreasing reliability in the longer term, increasing supply scarcity risk. The accelerated exit of coal and growing risk of plant failures is increasing the need for dispatchable projects currently progressing such as Tallawarra B in New South Wales and Jeeralang Battery in Victoria, as well as transmission to carry energy from Snowy 2.0 pumped hydro to consumer centres.
- **Accelerated interest in hydrogen production and greater electrification** – the timing and scale of sectors seeking to increase energy efficiency, lower greenhouse gas emissions, and reduce costs by fuel-switching to electricity (or, later in the outlook, hydrogen) is a major source of uncertainty. Different scenario assumptions show a range of possible outcomes to 2031, from minimal electrification to over 81 terawatt hours (TWh) of additional electrified load (including transport). The impact on maximum and minimum operational demand will depend on whether the right incentives, policies, and technologies are in place to make the load flexible.

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

Summer 2021-22 outlook

The interim reliability measure is forecast to be met

Expected unserved energy (USE) is forecast to remain below the Interim Reliability Measure (IRM) in all regions this summer.

Both peak demand and energy consumption are generally expected to be lower than was previously forecast for this summer, due to lower growth from the business mass market sector in line with recent trends and, in some regions, less large industrial load growth.

On the supply side, large amounts of new generation capacity continue to connect in the NEM. An additional 2,245 megawatts (MW) of new capacity is forecast to be operational this summer, compared to what was available last summer. This includes 470 MW of dispatchable battery storage capacity.

Risks to supply still exist, particularly during extreme events

The reliability of the thermal (coal and gas) generation fleet generally stayed at historically low levels in 2020-21, and AEMO expects (based primarily on reports from the owners and operators of this plant) that overall plant reliability will be at similar poor levels over the coming summer.

In Queensland, Callide C Unit 4 remains on extended outage after the operating incident that occurred on 25 May 2021², with return to service currently expected in late 2022. However, the forecast that USE in all regions will remain below the IRM is not expected to be affected by the unavailability of this Callide unit, nor by the announced mothballing of one unit of Torrens Island B in South Australia, nor by any potential delay to commissioning of the Victorian Big Battery due to the fire that occurred on 30 July 2021.

The USE outlook this summer and next could, however, be significantly affected by ongoing risks to the availability of Yallourn Power Station in Victoria. Recent flooding in the Morwell River diversion through the mine created cracks in the mine wall, putting it at greater risk of flooding during future heavy rainfall events. If the mine were to flood in a significant rainfall event, it could keep the entire power station out of service for 12-18 months.

AEMO analysed the potential impact if the entire Yallourn Power Station was unavailable for 18 months from October 2021, and found that expected USE would fail to meet both the IRM and the reliability standard. While the likelihood of such an event is relatively low, the consequence could be significant if the risk is not mitigated. AEMO is working with the Victorian Government to explore options that could help mitigate this risk.

Other risks to reliability this summer include:

- Prolonged periods of generation unavailability, including forced outages and/or potential mothballing.
- Transmission outages.
- Delays to the commissioning of new renewable generation or battery capacity.
- Extreme temperatures leading to wind farms significantly reducing generation output.
- The potential for gas supply shortfalls, particularly if gas generators need to operate more frequently to cover prolonged outages of major power stations.

Unserved energy (USE) is the amount of energy demanded, but not supplied due to reliability incidents. This may be caused by factors such as insufficient levels of generation capacity, demand response, or inter-regional network capability to meet demand.

The **Interim Reliability Measure (IRM)** is set to ensure that sufficient supply resources and inter-regional transfer capability exist to meet 99.9994% of annual demand for electricity in each NEM region, by helping keep expected USE in each region to no more than 0.0006% in any year.

Any **forecast reliability gap** is based on expected USE not meeting the IRM (or, from 30 June 2025, not meeting the **reliability standard**, which is 0.002% of expected USE in a region in a year).

If AEMO reports a forecast reliability gap, this triggers a reliability instrument request under the **Retailer Reliability Obligation (RRO)**.

² See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/preliminary-report--trip-of-multiple-generators-and-lines-in-queensland-and-associated-underfrequenc.pdf?la=en.

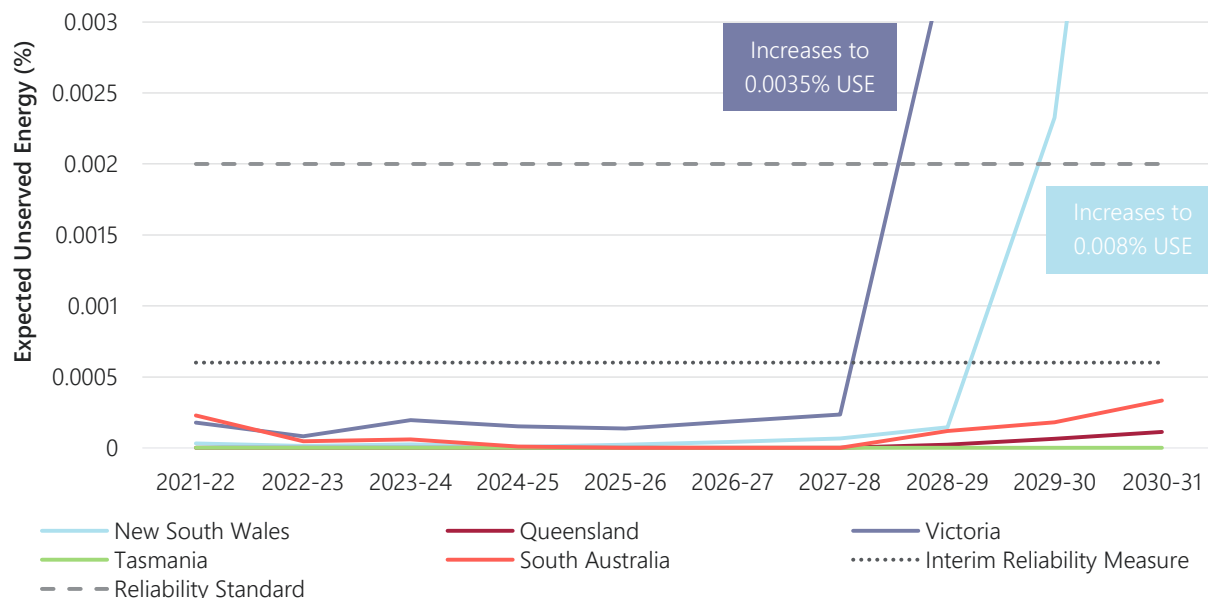
AEMO will mitigate these risks with the use of medium-notice and short-notice Reliability and Emergency Reserve Trader (RERT) resources in the first instance if required. This process ensures consumers do not pay for additional reserves unless they are needed, and that the benefits of calling on any out-of-market reserves outweigh the costs.

Beyond summer 2021-22

The reliability forecast has improved in the short to medium term – generation, storage, and transmission developments currently progressing will close reliability gaps forecast later in the outlook period

Figure 1 shows the reliability forecast from 2021-22 to 2025-26 and the indicative reliability forecast from 2026-27 to 2030-31. In the absence of additional investment, neither the IRM nor the reliability standard are forecast to be exceeded until more coal-fired power stations close from 2028 onwards. Multiple, well-advanced projects would mitigate the supply scarcity risk associated with these power station closures once final development and grid connection milestones are reached and/or enabling transmission (such as Humelink) is developed.

Figure 1 Expected unserved energy, 2021-22 to 2030-31, Central outlook



Reliability forecast in the next five years

In the medium term (next five years), the reliability forecast has improved since last year's ESOO, and the previously identified reliability gap in New South Wales is no longer forecast. This is primarily due to a combination of newly committed generation, storage, and transmission developments that were not included in the 2020 ESOO:

- As well as the 2.2 GW of new capacity (including 470 MW of storage capacity) noted earlier that is forecast to be operational by summer 2021-22, another 2.2 GW of new capacity is forecast to become operational within the next five years (in addition to Snowy 2.0's staged commissioning from 2025-26). That includes the following dispatchable projects:
 - The 750 MW Kurri Kurri Power Station in 2023-24³, partially replacing capacity lost with the retirement of the 2,000 MW Liddell Power Station in New South Wales over the 2022 and 2023 calendar years.

³ Treated as committed in this ESOO, as it is Federal Government policy to build this power station.

- The 154 MW Snapper Point Power Station (previously South Australia Temporary Generation North) in 2023-24, partially replacing capacity lost with the 2023 retirement of the 180 MW Osborne Power Station in South Australia.
- The Queensland 250 MW Kidston Pumped Hydro Energy Storage project in 2024-25.
- Project EnergyConnect, a new interconnector linking South Australia and New South Wales (with an added connection to Victoria) has now passed regulatory approvals and is assumed to commence operations in stages from 2023-24⁴. This is forecast to reduce supply scarcity risks by increasing transfer capacity between New South Wales and South Australia, allowing more resources to be shared across the NEM.
- Transfer capacity between Victoria, New South Wales, and Queensland is forecast to increase following various other transmission investments, further reducing supply scarcity risks. In addition to Queensland New South Wales Interconnector (QNI) Minor in 2022, which was included in the 2020 ESOO, these investments include:
 - Victoria New South Wales Interconnector (VNI) Minor in 2022 and 2023 (the Victorian components of this project were included in the 2020 ESOO).
 - The VNI System Integrity Protection Scheme (SIPS) in 2021, which will use reserve capacity from Victoria’s Big Battery to increase how much power can flow through the VNI.

Also in this five-year period, AGL is mothballing one unit of Torrens Island B Power Station from October 2021, with six months recall and return to service expected in 2024-25 to further support reliability following the withdrawal of Osborne Power Station.

On the demand side, AEMO now forecasts:

- Maximum demand in every mainland NEM region to be lower in the next five years, as (based on recent trends) the business mass market sector’s consumption is forecast to reduce.
- NEM overall operational consumption to fall under the ESOO Central projection, from 178 TWh in 2020-21 to 163 TWh in 2025-26, as households and businesses continue to install more distributed PV.
- Demand side participation (DSP) to remain at a similar level as forecast in 2020. Business and household consumers across the NEM are expected to provide up to 684 MW of DSP, using various options to reduce their demand at certain times in return for incentives.

AEMO is also tracking a pipeline of more than 2 GW of anticipated generation and storage projects that are well progressed in their development and are likely to become committed⁵, including Tallawarra B Power Station. These projects are not included in the reliability forecast, as they have not satisfied all criteria to be classed as committed, but will be considered in AEMO’s Draft 2022 *Integrated System Plan* (ISP), due in December 2021.

No forecast reliability gap is projected in any NEM region in the outlook period for the RRO. Consequently, AEMO will not be making any T-1 or T-3⁶ reliability instrument requests⁷ based on this reliability forecast.

In the 2020 ESOO, AEMO reported a forecast reliability gap for New South Wales in 2023-24, which resulted in the Australian Energy Regulator (AER) creating a T-3 reliability instrument. This reliability gap is no longer forecast.

⁴ Based on AER approval of the contingent project application and confirmation of funding by transmission network service providers (TNSPs).

⁵ For more information see AEMO’s Generation Information publication at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>. “Anticipated” and “committed” are defined under the Background Information tab on each Generation Information spreadsheet, and are based on meeting set criteria.

⁶ T-3 is 3 years from any forecast reliability gap and T-1 is 1 year from any forecast reliability gap. For this ESOO, a forecast reliability gap in 2024-25 would have triggered a T-3 reliability instrument request, and for South Australia, where a T-3 reliability instrument already exists for the 2022-23 year, a forecast reliability gap in that same year would have triggered a T-1 reliability instrument request.

⁷ For more information on the RRO, see <http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules>.

Indicative reliability forecast in 5-10 years

Changes in supply influence the USE outlook in years 5-10 of the forecast period (from 2026-27 to 2030-31):

- Generator retirements have been brought forward into the 10-year outlook period, with owners announcing the earlier closures of Yallourn Power Station (brought forward to 2028), and one unit of Eraring Power Station (to 2030). As well as these changes since the last ESOO, AEMO still expects the Vales Point Power Station to close in 2029.
- Western Victoria transmission upgrades are now expected to be completed in 2025-26, reducing supply scarcity risks by increasing the amount of power that can flow between Victoria and other regions.

Although AEMO now has more detail on the commissioning of Snowy 2.0, with 2 GW of capacity expected to become available gradually between 2025-26 and 2026-27, including this supply has a negligible impact on expected USE because the transmission to carry the energy to consumer centres is not yet committed.

No new wind, large-scale solar, gas or battery energy storage system (BESS) developments are sufficiently progressed to be classed as committed for development in this timeframe, above what will already be developed in the next five years. However, there are multiple projects well advanced and close to satisfying AEMO's commitment criteria once final development and grid connection milestones are reached.

Both maximum demand and consumption forecasts grow more strongly in the second five years of the decade than they do in the short term, and by 2030-31 are similar to where the 2020 ESOO forecast they would be. The higher growth in the second five years is driven by AEMO's projections that:

- Household consumption will grow, as population growth means more connections, and consumers increase their use of electric appliances.
- Business consumption will pick up after the next five years and grow again.
- Businesses and households switching from other fuels to electricity, to reduce costs and emissions, will add about 3% to electricity use overall under the Central scenario (with variation between regions).

In AEMO's indicative reliability forecast for this five-year period, expected USE stays below the reliability standard in all regions until 2028-29, when the closures of large generators start to affect forecast reliability. That said, the development of generation and storage projects that are well progressed, along with key enabling transmission, is expected to close the forecast reliability gaps identified in the next decade.

- In Victoria, the rescheduled closure of Yallourn Power Station in 2028-29 impacts forecast reliability in that region. As part of an agreement with the Victorian Government, Energy Australia has committed to developing a 350 MW four-hour large-scale battery project before Yallourn retires (Jeeralang Battery). While this project does not yet meet AEMO's commitment criteria, the project is underway and, once built, would close much of the forecast reliability gap in Victoria towards the end of the decade.
- In New South Wales:
 - The inclusion of the 750 MW Kurri Kurri Power Station has improved the reliability outlook, compared to the 2020 ESOO forecast. Previously, after the closure of Vales Point Power Station in 2029, the Sydney, Newcastle and Wollongong area would need supply at peak times from existing and committed generation outside the area. Network congestion would not allow this to happen, so AEMO forecast significant expected USE. Now additional new dispatchable capacity has been committed in the Hunter Region, the Sydney, Newcastle and Wollongong area will not rely as heavily on supply from elsewhere to meet peak demand, delaying the supply scarcity risk until the next coal closure after Vales Point Power Station (currently, one unit of Eraring in 2030). The anticipated development of Tallawarra B would further delay this risk.
 - Transmission developments – such as the Sydney Reinforcement project identified in the 2020 ISP – would help by alleviating network congestion so more supply can be delivered to the Sydney, Newcastle and Wollongong area at peak times. Development of the HumeLink transmission project would also help realise the reliability benefits associated with Snowy 2.0.

Implications and opportunities of accelerated deployment of large-scale and distributed renewable resources

Consumers continued to invest in distributed PV in the last year, more strongly than AEMO anticipated in the 2020 ES00. AEMO now forecasts an additional 8.9 GW of distributed PV capacity will be installed by 2025 (on top of the current installed capacity of around 14 GW) in its Central scenario.

As households and businesses supply more of their own energy from distributed PV and storage, they draw less electricity from the grid. As the penetration of distributed PV continues to accelerate, AEMO now forecasts that:

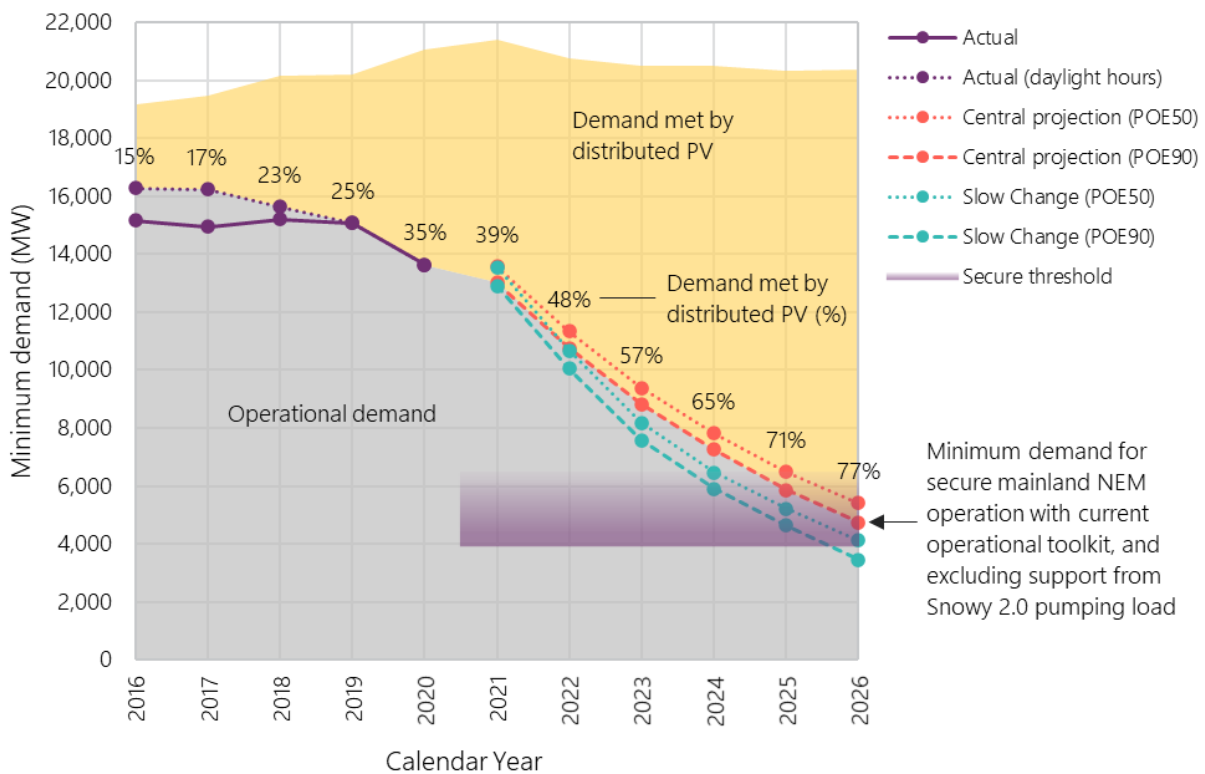
- All NEM mainland regions will experience minimum operational demand – the lowest level of demand from the grid – in the daytime during the next five years.
- The challenges and opportunities created by falling minimum demand will be experienced earlier than has been expected.

On 29 September 2019, the NEM mainland (excluding Tasmania) experienced a daytime minimum demand record of 15 GW. This is forecast to decrease to around 6 GW by 2025-26 in the Central scenario.

Figure 2 shows the rapid decline in minimum demand forecast in the NEM mainland.

For the power system to be operated securely, with the tools currently available to AEMO, there are thresholds demand cannot fall below. This ES00 shows that the whole NEM mainland is expected to reach these thresholds within the next five years in some scenarios, making it increasingly challenging for AEMO to operate the NEM with all the required security services. When Snowy 2.0 starts operating and drawing electricity for pumping, this threshold may lower slightly, however the forecast rate of decline in minimum demand will mean this additional scheduled load is not sufficient in isolation to address system security challenges long term.

Figure 2 Minimum demand on the NEM mainland (excluding Tasmania)



Notes: 90% probability of exceedance (POE) means demand is expected to be lower than forecast one year in 10; 50% POE means demand is expected to be lower one year in two. Forecasts are “as generated”, meaning they are measured at each generating unit’s terminal point and represent the unit’s gross electrical power output, including power “sent out” to meet demand and power used to operate the generating unit.

The transition to a power system supplied almost entirely by renewable and distributed resources in some periods represents a major change in power system and electricity market operation. A range of adaptations will be needed for the power system to keep operating securely, reliably, safely and affordably. These adaptations fall into four categories:

- Social licence for active management of distributed energy resources (DER) like distributed PV – consumers are at the centre of this transition, and AEMO and the energy industry need to build relationships of trust with them.
- Foundational power system security adaptations – engineering solutions can provide a robust and resilient foundation for the power system to operate securely.
- Adapted market and regulatory frameworks – these can unlock opportunities for consumers to fully participate in markets, and provide incentives so the choices made by consumers and industry stakeholders align with system needs.
 - The Energy Security Board (ESB) delivered policy direction for adaptations to market and regulatory frameworks in its Post 2025 market design program to Energy Ministers in July 2021. This ESB direction includes initiatives to integrate DER into the system (rewarding consumers for their flexibility in DER and demand-based assets), creation of new system services, and arrangements for the management of early exit of existing coal-fired generators.
- Emerging opportunities for stakeholders – new services will be needed to operate a power system with a high penetration of distributed PV, and the market could provide solutions such as:
 - Providing frequency control ancillary services (FCAS), fast frequency response (FFR) and recovery services, load shifting, and active management of DER.
 - “Soaking” excess solar generation, by storing it or having demand flexibility, so when solar is plentiful it can be used to benefit consumers and there is no need to curtail either large-scale renewable generation or consumers’ distributed PV (this should be a last resort). Demand flexibility solutions could be provided through new uses for electricity, such as hydrogen production and electrification of industrial processes and transport. For storage, there is already a pipeline of publicly announced storage projects⁸ (beyond those already operating and committed for operation) that includes 21 GW of battery storage and 6.3 GW of medium to long-term duration storage across the NEM.

AEMO forecasts an increasingly frequent need for these solutions. Instantaneous penetration of renewable generation reached a record high 57% of underlying demand across the NEM on 11 April 2021, and a new record of 57.1% on 22 August 2021⁹; that means approximately 57% of all the electricity used in the NEM at these times came from renewable sources. Based on current trends, AEMO expects that, if the power system is engineered appropriately, there could be up to 100% instantaneous penetration of renewables at certain times of the day throughout the year by 2025.

Figure 3 shows:

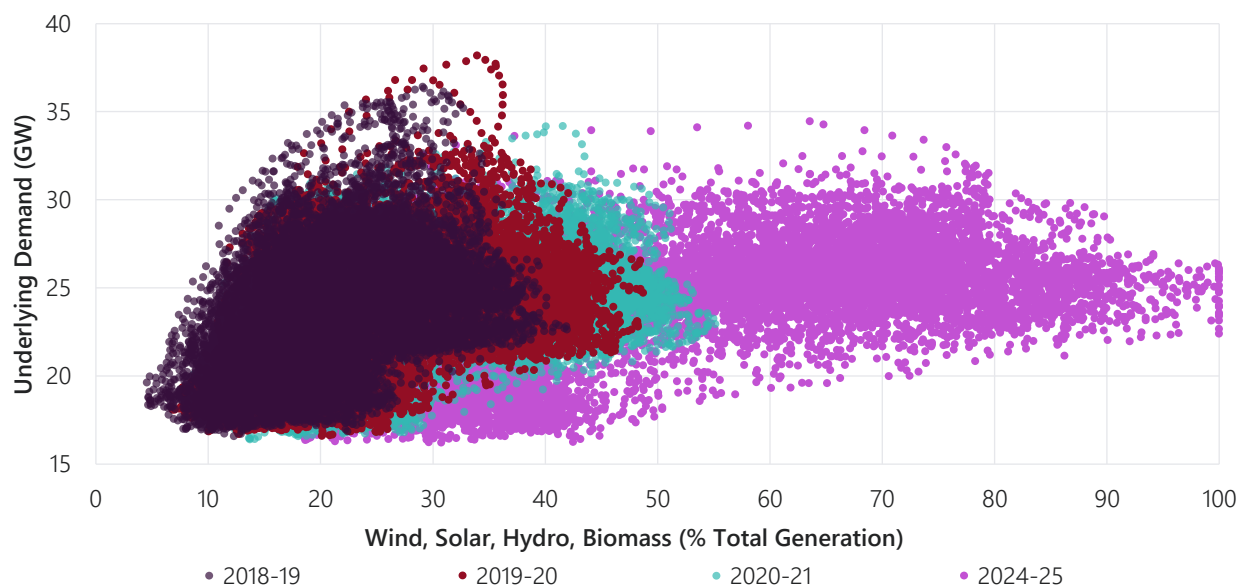
- The recent historical trend (from 2018-19 to 2020-21) for increasing penetration of renewable resources including wind, solar (large-scale and distributed), hydro, and biomass.
- An estimate of the instantaneous penetration of renewables for 2024-25 based on resource potential of existing, committed, and anticipated projects and distributed PV. A high proportion of this renewable generation is from inverter-based resources (IBR, meaning wind and solar generation including distributed PV). As the power system contains more IBR and less synchronous generation (particularly coal-fired and gas-fired generation), the change creates new challenges and opportunities for secure system operation¹⁰.

⁸ As published on AEMO’s Generation Information page, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

⁹ The records occurred in the trading interval ending 1130 hours on 11 April 2021, and in the trading interval ending 1330 hours on 23 August 2021.

¹⁰ See AEMO, *Advanced Grid-Scale Inverter White Paper*, at <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf>.

Figure 3 NEM-wide penetration of renewable resources (large-scale and distributed), 2018-19 to 2020-21, with indicative resource potential forecast for 2024-25 based on existing, committed, and anticipated projects and distributed PV forecasts



Managing an accelerated transition – exit of coal and increasing risk of plant failures

AEMO models its reliability forecasts based on expected closure dates provided by industry participants¹¹.

However, the accelerated rate of change in the energy industry has implications for the ongoing financial viability of existing thermal generation. This was highlighted by announcements since the 2020 ESOO that owners were bringing forward the closures of Yallourn Power Station (by four years, to 2028) and two units at Eraring Power Station (one unit by two years, to 2030 and one unit by one year, to 2031). One unit of Torrens Island B Power Station has also been mothballed for a three-year period commencing October 2021, with the owner saying this decision was in response to challenging market conditions¹².

Further, long duration outages of plant continue to disrupt the NEM. Most recently, the incident at Callide C, and flooding at Yallourn both threatened system reliability and only two years ago, the prolonged outages at Loy Yang A and Mortlake significantly reduced supply in Victoria.

To inform participants, policy-makers, and other stakeholders of the impact of sudden outages or closures of major generators, AEMO is publishing additional modelling on the implications of further early closures in this ESOO. A sensitivity study shows that, in the absence of additional investment such as commissioning of anticipated projects or development of transmission, an early closure of Yallourn would immediately trigger exceedance of the reliability standard in Victoria. Similarly, the early closure of Vales Point and one unit of Eraring would trigger exceedance of the reliability standard in New South Wales. If unplanned, this exit would pose substantial risk to consumers as there would be little time for the market to respond.

This highlights the need for mechanisms such as those proposed by the ESB in its Post 2025 market design program to manage the exit of coal-fired generation. Should transmission become committed to provide the NEM access to additional Snowy 2.0 reserves, this would also help increase system resilience to withstand reliability impacts of unplanned events or early closures.

¹¹ Published and regularly updated on AEMO’s Generation Information page.

¹² See AGL’s media release at <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/july/agl-to-mothball-one-unit-at-torrens-b-in-south-australia>.

Managing an accelerated transition – interest in hydrogen production and greater electrification

Hydrogen

For the first time, the 2021 ESOO includes consideration of green hydrogen as a scenario in its modelling.

Momentum is building in the industry as the development of a hydrogen economy may simultaneously enable a significant new export opportunity and provide a means to achieve carbon emission reduction objectives. There are now more than 10 projects at the 100+ MW scale being actively developed across Australia, and many more at a smaller scale. Government funding initiatives and strategies continue to show strong interest in, and support for, developing Australia's hydrogen potential, including the Federal Government's Technology Investment Roadmap¹³.

This ESOO projects that if demand for green hydrogen increases rapidly, the NEM could experience significant load growth and greater load flexibility. This demand would be expected to take advantage of the flexibility of proton exchange membrane (PEM) electrolyzers, avoiding periods of electricity supply scarcity and operating when energy was readily available in the middle of the day.

Electrification

Fuel-switching in the form of electrification as a direct substitution for fossil fuels is one of the most cost-effective decarbonisation options for sectors that use energy. Like hydrogen, this has the potential to materially increase electricity consumption in the NEM.

In the 2021 ESOO, AEMO has considered a broad range of sectors (beyond transport) with potential to be electrified. These forecasts reflect a range in the potential magnitude and timing of impacts to demand over the next decade if household, business, and industrial energy users switch to electricity to decarbonise, reduce energy costs, and, in some cases, increase fuel efficiencies.

ESOO analysis suggests that, in the NEM alone, fuel-switching from other fuels to electricity could be as high as 81 TWh by 2030-31, equivalent to 46% of total current operational consumption in the NEM, if there are strong incentives for electrification of transport, residential and industrial sectors. Electrification of heating load also has the potential to switch maximum operational demand from summer to winter, particularly in Victoria where many consumers currently use gas for heating their homes.

As the energy transition accelerates, the decarbonisation of other sectors also needs careful planning of the interface with the energy system. This will require the right incentives, policies, and technologies to make load more flexible in order to maximise the value our energy system can deliver.

¹³ At <https://www.industry.gov.au/sites/default/files/September%202020/document/first-low-emissions-technology-statement-2020.pdf>.

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 about:

- Existing, committed, and proposed electricity supply and network capabilities.
- Planned generating plant retirements.
- Operational consumption, maximum and minimum demand forecasts.
- Potential unserved energy (USE) in excess of the reliability standard and Interim Reliability Measure (IRM) 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 2021 ESOO:

- The 2021 ESOO report and supplementary information published on the 2021 ESOO webpage¹⁴.
- Demand forecasting data portal¹⁵.
- The July 2021 Generation Information page update¹⁶.
- The 2021 *Inputs, Assumptions and Scenarios Report* (IASR), accompanying workbook and supplementary material¹⁷.

To meet the obligations under the Retailer Reliability Obligation (RRO)¹⁸, the ESOO also includes:

- **Reliability forecasts** identifying any potential reliability gaps for each of this financial year and the following four years (see Section 5.2).
- **Indicative reliability forecasts** of any potential reliability gaps for each of the final five years of the 10-year ESOO forecast period (see Section 5.3).

Reliability forecast under the RRO

In the 2021 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute Chapter 5 in this report. Key component forecasts and inputs include:

- Consumption and demand forecasts (see Sections 2.2, 2.3, and 2.4, the demand forecasting data portal, and the demand traces).
- Supply forecasts (see Chapter 3 and the renewable generation traces).

¹⁴ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

¹⁵ At <http://forecasting.aemo.com.au/>

¹⁶ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

¹⁷ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies>.

¹⁸ The RRO came into effect on 1 July 2019 through changes to the National Electricity Law, the NER, and South Australian regulations. For more information, see <http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules>.

- The accompanying July 2021 Generation Information page.
- Sections of the 2021 IASR¹⁹ that comprise the Forecasting Components of the Forecasting Approach for ESOO and Reliability Forecast purposes:
 - Annual consumption forecast components (for large industrial load, commercial, residential, and connections forecasts) and maximum and minimum demand forecasts, including demand traces (Section 3.3 of the 2021 IASR).
 - Distributed energy resources (DER) forecasts (Section 3.3.6 of the 2021 IASR).
 - Renewable generation traces (Section 3.6.2 of the 2021 IASR).
 - Demand side participation (DSP) forecasts (Section 3.3.13 of the 2021 IASR).
 - Generator outage rates (Section 3.4.3 of the 2021 IASR).

Operational consumption by consumer segment and maximum and minimum demand forecasts are provided over a 10-year period from financial year 2021-22 to 2030-31 in Chapter 2. These are primary component forecasts of AEMO's Forecasting Approach²⁰, used to develop the reliability forecasts and indicative reliability forecasts presented in the following chapters. Secondary forecasting components such as connections forecasts or DER forecasts are provided in the 2021 IASR.

Operational consumption and maximum and minimum demand forecasts are provided over a 30-year period from the financial year 2021-22 to 2050-51 for each NEM region in Appendices A1-A5. These forecasts are used by stakeholders for a range of other purposes, including longer-term planning studies.

1.2 Key definitions

Reliability forecast components

Unserviced energy (USE)²¹ is the amount of energy demanded, but not supplied, due to reliability incidents. This may be caused by factors such as insufficient levels of generation capacity, demand response, or inter-regional network capability to meet demand.

The NEM **reliability standard** is set to ensure that sufficient supply resources and inter-regional transfer capability exists 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 **Interim Reliability Measure (IRM)** allows for a maximum expectation of 0.0006% of energy demand to be unmet in a given region per financial year. It was introduced by the National Electricity Amendment (Interim Reliability Measure) Rule 2020 (IRM Rule). The IRM Rule and changes to the RRO rules²² are intended to support reliability in the system while more fundamental reforms are designed and implemented. The use of the measure for contracting reserves and for the RRO is currently set to expire in June 2025, after which the reporting obligation reverts to the previous position under the NER, that AEMO must report on whether the reliability standard would be exceeded in any financial year.

¹⁹ At <https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies>.

²⁰ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach>.

²¹ The USE that contributes to the reliability standard excludes power system security incidents resulting from events such as multiple or non-credible generation and transmission events, network outages that do not materially contribute to inter-regional transfers, or industrial action (NER 3.9.3C(b)(2)). 'Expected' in this ESOO refers to the statistical definition of the word, which describes the weighted-average USE over a wide range of simulated outcomes.

²² Temporary changes to the RRO were introduced by the National Electricity Amendment (Retailer Reliability Obligation trigger) Rule 2020. They expire in June 2025.

Reliability forecast under the RRO

For the RRO, components of any reliability forecast or indicative reliability forecast must include the expected USE, and whether or not there is a **forecast reliability gap**. Such a gap exists for a NEM region, if the expected USE exceeds the IRM up until 30 June 2025, or exceeds the reliability standard from 1 July 2025 onwards. 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).

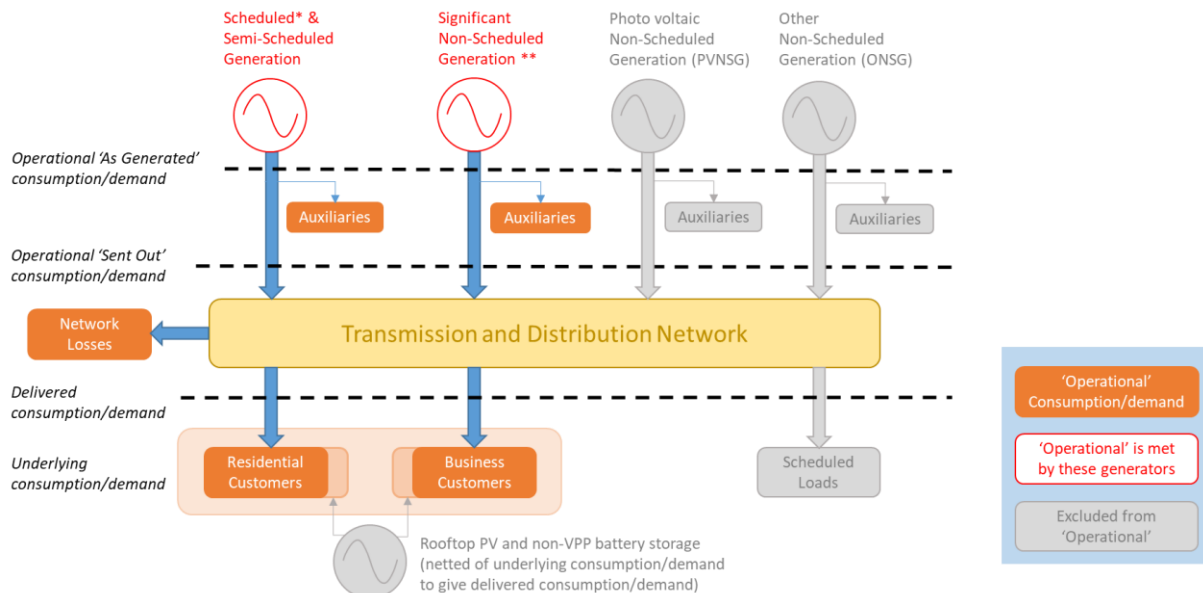
AEMO's calculation of the size of the forecast reliability gap represents the additional megawatts of firm capacity required to reduce the annual expected USE to the reliability standard. This capacity is assumed to be 100% available during all identified trading intervals within the forecast reliability gap period only.

Demand forecasts

Electricity **consumption** represents electricity consumed over a period of time – in the context of this report, annually – while **demand** is used as a term for the instantaneous consumption of electricity at a particular point in time, typically at time of maximum or minimum demand.

Consumption and demand can be measured at different places in the network. Unless otherwise stated, the forecasts in this report refer to **operational consumption/demand (sent out)**²³. This is the supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator). Also excluded from this definition is consumption/demand from scheduled loads (typically pumping load from pumped hydro energy storage or large-scale batteries). Demand definitions are shown in Figure 4.

Figure 4 Demand definitions used in this report



* Including virtual power plants (VPPs) from aggregated behind-the-meter battery storage.

** For definitions, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

²³ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

This ESOO reports consumption forecasts for each sector (residential and business) as **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 consumption/demand means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' distributed photovoltaics (PV) and battery storage.

Maximum and minimum operational demand means the highest and lowest level of electricity drawn from the grid at any one time in either summer (1 November to 31 March) or winter (1 June to 31 August). These forecasts are presented as **sent out** (the electricity measured at generators' terminals) and **as generated** (including auxiliary loads).

Maximum and minimum operational 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 (also called one-in-two year).
- A **10% POE** (for maximum demand) or **90% POE** (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called one-in-10).
- A **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be expected nine years in 10.

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

Overall approach to forecasting reliability

Following extensive stakeholder consultation, AEMO has forecast reliability of supply for the NEM in the 2021 ESOO by:

- Developing 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, including electrification impacts. The forecasts for operational consumption and demand also reflect forecasts for implemented energy efficiency measures and growth in distributed PV generation and battery storage systems.
- Updating the supply available to meet this demand to include the latest information on existing and committed generation in the NEM and expected closures.
- Reviewing the performance of existing scheduled generation based on historical performance data, and incorporating forward-looking projections of plant reliability for coal-fired and large gas-fired generators that take into account the impact of maintenance plans, deterioration due to age, and reductions in maintenance as generators approach retirement.
- Applying a statistical simulation approach²⁴ which assesses the ability of existing and committed²⁵ generation to meet forecast demand in all hours. The model calculates expected USE over a number of demand and renewable generation outcomes (based on 11 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 expected USE.

²⁴ See ESOO Methodology Report, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

²⁵ 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>.

AEMO does not include pain sharing (spreading of USE throughout interconnected regions in proportion to demand) in ESOO modelling. Instead, the annual USE reported in a region reflects the source of any supply shortfall, and is intended to provide participants with the most appropriate locational signals to drive efficient market responses.

More details on the methodologies, inputs, and assumptions used to develop the demand and supply forecasts and assess expected USE are available in the accompanying information listed in Table 3.

USE and investment needs

In this ESOO, AEMO compares the expected USE calculated through the statistical model against the maximum threshold specified by the reliability standard and the IRM.

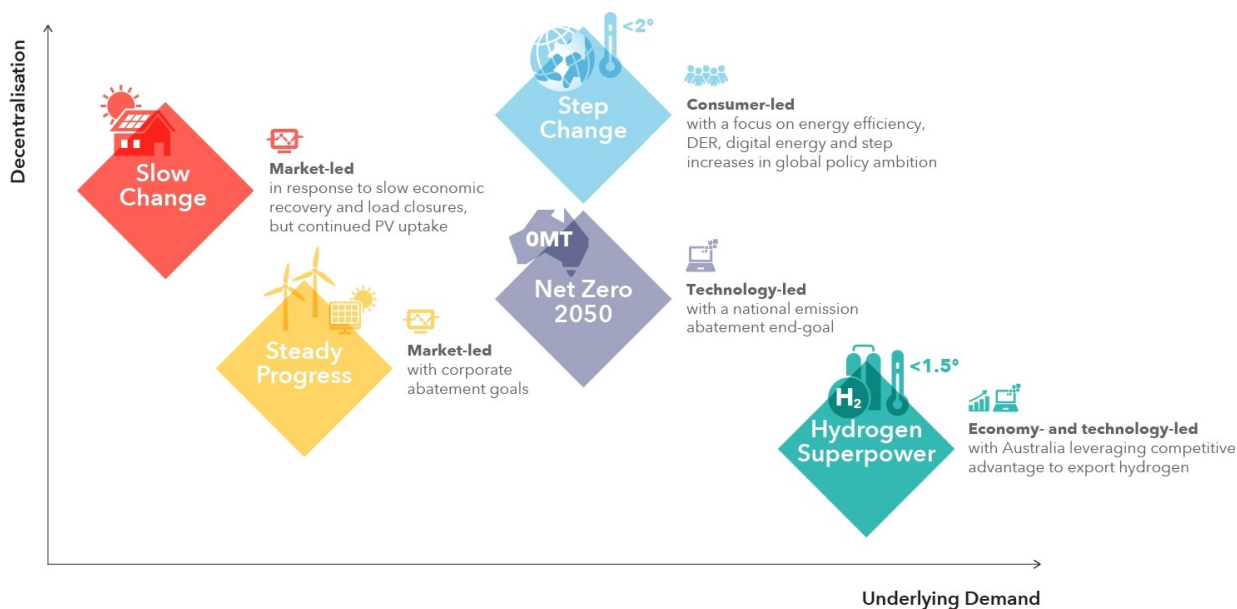
For the RRO, if the USE is expected to exceed the relevant threshold, AEMO calculates the forecast reliability gap size, indicating the need (in megawatts) for dispatchable generation or equivalent within the forecast reliability gap period to reduce USE so the IRM or reliability standard will be met.

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

1.4 Scenarios and sensitivities

In consultation with industry and consumer groups AEMO developed five scenarios and additional sensitivities for use in its 2021-22 forecasting and planning publications, including the upcoming 2022 *Integrated System Plan* (ISP).

Figure 5 2021-22 scenarios for AEMO's forecasting and planning publications



These scenarios and sensitivities have been applied in this ESOO as follows:

- Consumption and demand forecasts for each of the five scenarios, across the 30-year forecast period 2021-22 to 2050-51, are presented for each region in Appendices A1-A5.

- For RRO purposes, AEMO’s Reliability Forecast Guidelines²⁶ require the reliability forecast and indicative reliability forecast to be determined on a neutral or central scenario. For the 2021 ESOO, AEMO has adopted both the Net Zero 2050 and Steady Progress scenarios as the central demand scenario, noting that these scenarios are equivalent over the 2021 ESOO 10-year timeframe. These scenarios are referred to as the ‘Central’ scenario throughout this report.
- The 2021 ESOO focuses on this Central scenario, but also assesses supply adequacy for two alternative futures (Slow Change and Hydrogen Superpower) over the 10-year outlook, as outlined in Table 2.
- For understanding potential consumption and demand impacts of fuel-switching and electrification, AEMO has also modelled a Strong Electrification sensitivity (discussed in Section 6.3), as a variant on the Hydrogen Superpower scenario. This sensitivity explores possible changes to the power system if there is a strong switch to electrification.

Table 1 summarises the scenarios presented in this ESOO; more information is available in the 2021 IASR²⁷. The latest inputs and assumptions applied to these scenarios have been consulted on since December 2020, and are also outlined in the IASR and summarised in Table 2 as relevant to the demand forecasts.

Table 1 Descriptions of 2021-22 scenarios for AEMO’s forecasting and planning publications

Slow Change	Challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures, slower decarbonisation action, and consumers proactively managing energy costs through continuing investments in DER, particularly distributed PV.
Steady Progress (ESOO Central scenario)	Future driven by existing government policy commitments, continuation of current trends in consumer investments such as DER and corporate emission abatement, and technology cost reductions. By 2050, many consumers are still relying on gas for heating.
Net Zero 2050 (ESOO Central scenario)	Action towards an economy-wide net zero emissions objective by 2050 through technology advancements. Short-term activities in low emission technology research and development enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s, with stronger economy-wide decarbonisation, particularly industrial electrification, as 2050 approaches. Electric vehicles (EVs) become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.
Step Change	A future with rapid consumer-led transformation of the energy sector and a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions. This requires a step change in global policy commitments to achieve the minimum objectives of the Paris Agreement, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation enhances the role consumers can play in managing their energy use, along with advancements in energy efficient technologies and buildings. EV adoption is strong, with early decline in manufacturing of internal-combustion vehicles. By 2050, most consumers rely on electricity to heat their homes and businesses. Carbon sequestration in the land use sector helps offset hard-to-abate emissions.
Hydrogen Superpower	Strong global action towards emissions reduction, with significant technological breakthroughs and social change to support low and zero emissions technologies. Emerging industries such as hydrogen production present unique opportunities for domestic developments in manufacturing and transport, and renewable energy exports via hydrogen become a significant part of Australia’s economy. New household connections tend to rely on electricity for heating and cooking, but those households with existing gas connections progressively switch to using hydrogen – first through blending, and ultimately through appliance upgrades to use 100% hydrogen.
Strong Electrification sensitivity	A high emissions-reduction future, aligned with the decarbonisation objectives of the Hydrogen Superpower scenario, only in this future, hydrogen uptake is limited and energy efficiency is also more muted. This leaves the majority of the emissions reductions to be achieved through electrification, testing the outer bounds of the existing system. No export hydrogen or associated green steel manufacturing facilities are therefore included in this sensitivity.

²⁶ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

²⁷ At <https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies>.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2021 ESOO

Scenario/sensitivity	Slow Change	Central*	Hydrogen Superpower	Strong Electrification
Economic growth and population outlook	Low	Moderate	High	High
Energy efficiency improvement	Low	Moderate	High	High
DSP growth	Low	Moderate	High	High
Distributed PV	Moderate, but elevated in the short term	Moderate	High	High
Battery storage installed capacity	Low	Moderate	High	High
Battery storage aggregation / virtual power plant (VPP) deployment	Low	Moderate	High	High
Battery electric vehicle (EV) uptake	Low	Moderate	Moderate/High	High
EV charging time switch to coordinated dynamic charging	Low	Moderate	Moderate/High	Moderate/High
Electrification of other sectors (expected outcome)	Low	Low/Moderate	Moderate/High	High
Hydrogen consumption	Minimal	Minimal	Large NEM-connected export and domestic consumption	Minimal
Decarbonisation target	26-28% reduction by 2030	26-28% reduction by 2030	Exceeding 26-28% reduction by 2030, consistent with global targets for a <1.5°C mean rise in temperature by 2100.	Exceeding 26-28% reduction by 2030, consistent with global targets for a <1.5°C mean rise in temperature by 2100.

* As noted above, the Central forecast reflects both the ISP Steady Progress and Net Zero 2050 scenarios, which are equivalent over the 10-year ESOO timeframe.

1.5 Additional information for 2021 ESOO

Table 3 provides links to additional information provided either as part of the 2021 ESOO accompanying information suite, or in related AEMO planning information.

Table 3 Links to supporting information

Information source	Website address and link
AEMO Forecasting Approach: <ul style="list-style-type: none"> • <i>Demand Forecasting Methodology Information Paper</i> • <i>DSP Forecasting Methodology</i> • <i>Reliability Forecast Guidelines</i> • <i>ESOO and Reliability Forecast Methodology Document</i> 	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach

Information source	Website address and link
2021 Inputs, Assumptions and Scenarios Report (IASR)	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
2021 ESOO supplementary results, data files, and constraints, including: <ul style="list-style-type: none"> • 2021 ESOO model and user guide • 2021 ESOO demand and variable renewable energy traces • 2021 ESOO reliability outcomes by region 	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
Reliability Standard Implementation Guidelines (RSIG)	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines
Demand forecasting data portal	http://forecasting.aemo.com.au/
Forecasting Accuracy Reporting and Forecast Accuracy Report Methodology	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
Generation Information web page	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
Integrated System Plan	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp
Forecasting Best Practice Guidelines Compliance Report	To be provided to the Australian Energy Regulator (AER) at the time of publishing, and subsequently published by the AER.
Consultant reports supporting the development of the 2021 IASR and ESOO	
BIS Oxford Economics, 2021 Macroeconomic Projections Report	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf?la=en
CSIRO, 2021 DER Forecasts Report	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf?la=en
Green Energy Markets, 2021 DER Forecasts Report	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en
CSIRO Multi-sector modelling	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf?la=en
AEP Elical – Assessment of Ageing Coal-Fired Generation Reliability	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

2. Demand forecasts

Consumer demand is a key consideration in the assessment of supply adequacy. This chapter discusses the consumer demand forecasts used in this ESOO, focusing on the next 10 years, and reports that:

- Operational consumption is forecast to decline in the next five years, as distributed PV uptake continues.
- Later in the decade, growth is forecast to return, driven by the commercial sector and an acceleration in the rate of electrification, particularly electric vehicles (EVs).
- In the longer term, scenario uncertainty increases, with the potential for accelerated deployment of DER, hydrogen, and electrification driving high scenarios, while the potential for industrial load closures and sluggish economic growth drives lower scenarios.
- Maximum demand continues to soften over the next five years, then increases from 2025-26 through growth in residential and commercial sector demand.
- With the sustained uptake of distributed PV, minimum demand forecasts show a rapid decline.

Despite the COVID-19 downturn in the economy, strong uptake of distributed PV continued in 2020-21, with approximately 2.6 gigawatts (GW) of new installations – much stronger than had been anticipated last year during the initial phases of the pandemic. AEMO forecasts this strong growth of installations to be maintained in the medium term, and this is the most material driver impacting operational consumption forecasts.

Accordingly, under the Central scenario, operational consumption is forecast to reduce from 178 terawatt hours (TWh) in 2020-21 to 163 TWh in 2025-26, largely due to distributed PV uptake. Additionally, forecast investment in energy efficiency activities also tend to partially offset growth in consumption due to new household connections.

In the second half of the decade, operational consumption is generally expected to moderately recover, increasing to 168.5 TWh in the Central outlook by 2030-31. This medium-term growth, while continuing to be moderated by investment in distributed PV and energy efficiency activities, is driven by:

- Continued growth in residential load, coming from growth in household connections.
- Business load starting to grow from 2025 onwards, particularly from the commercial sector as it is projected to grow its share of the economy.
- Increasing electrification (consumers switching to electricity from other fuels), including uptake of EVs.

This projected growth sees demand approach similar levels to the 2020 ESOO forecasts towards the end of the decade, after the initial dip in the first five years.

Longer term (10 to 30 years), structural drivers such as population growth, economic growth, electrification (including EVs), energy efficiency, and technology adoption all have potential to materially influence operational consumption. By 2050, under some scenarios, NEM consumption is forecast to be two to five times larger than today; this is further discussed in Appendices A1-A5.

Maximum and minimum demand forecasts are influenced by similar structural and technological drivers, although these drivers – coupled with random weather-driven elements, co-incident consumer behaviours, and extent of co-ordination of consumer-owned energy devices – can impact extreme forecasts quite differently to annual consumption. For example, in the Central outlook, while operational consumption does not increase above 2020-21 historical levels by the end the next decade, maximum operational demand is forecast to experience average annual growth of between 0.4% and 1.2% across mainland NEM regions.

With the exception of Tasmania, maximum operational demand now frequently occurs at sunset in summer, when distributed PV uptake has little moderating impact on other fundamental drivers of growth, such as new connections or appliance uptake.

Conversely, due to the continued growth in distributed PV, minimum demand is projected to occur in the middle of the day in all regions except Tasmania from now on, with minimum demand decline being directly proportional to growth in distributed PV.

Due to the varying effects of distributed PV uptake, operational demand is becoming more variable over a year, with higher highs and lower lows while overall consumption remains relatively flat. Tariff reform or aggregation, digitalisation, and co-ordination of consumer-owned energy devices in a way that can provide both grid flexibility and value to device owners will become increasingly important for managing this variability.

The consumption and demand forecasts in this chapter are presented on an operational (sent out) basis and focus on the next 10 years in line with the ESOO planning horizon. Longer-term forecasts to 2050 used in AEMO's forecasting and planning activities such as the ISP, are presented in the appendices for each region.

Forecasts of key drivers, such as distributed PV, battery and electric EV uptake, energy efficiency savings, electrification of other sectors, new household connections, and economic growth are discussed in AEMO's 2021 IASR.

The regional and component demand forecasts are available to view and download from AEMO's Forecasting Portal²⁸.

2.1 Underlying energy consumption continues to grow with population, economic activity and electrification

The key drivers acting to influence the consumption forecasts affect residential, business mass market, and industrial consumer segments differently.

Figure 6 below shows annual consumption by consumer segment for the Central outlook, and highlights the various influencing factors contribute to changes in consumption over the next decade.

Figure 7 shows the relative impact of each component, across the different scenarios, by 2030-31.

Each region in the NEM has similar macro level drivers for population and economic activity, although different aspects in the size and composition of each sector give rise to regional nuances. For example, Victoria has more gas heating load and potential for residential electrification than other regions, while Tasmania and Queensland have a much lower amount of gas usage for heating and a much lower potential for electrification. Regional trends and drivers are discussed in Appendices A1 to A5.

²⁸ At <http://forecasting.aemo.com.au/>.

Figure 6 NEM electricity consumption, actual and forecast, 2012-13 to 2030-31, Central scenario

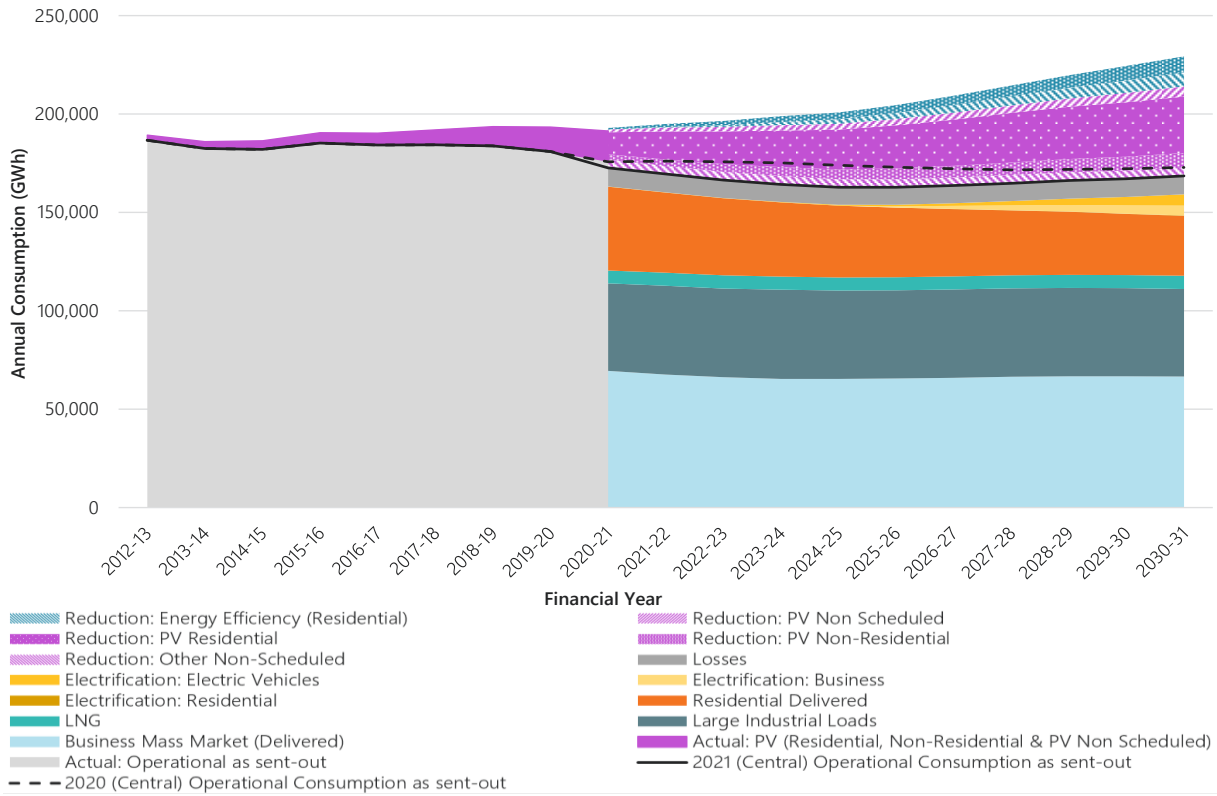
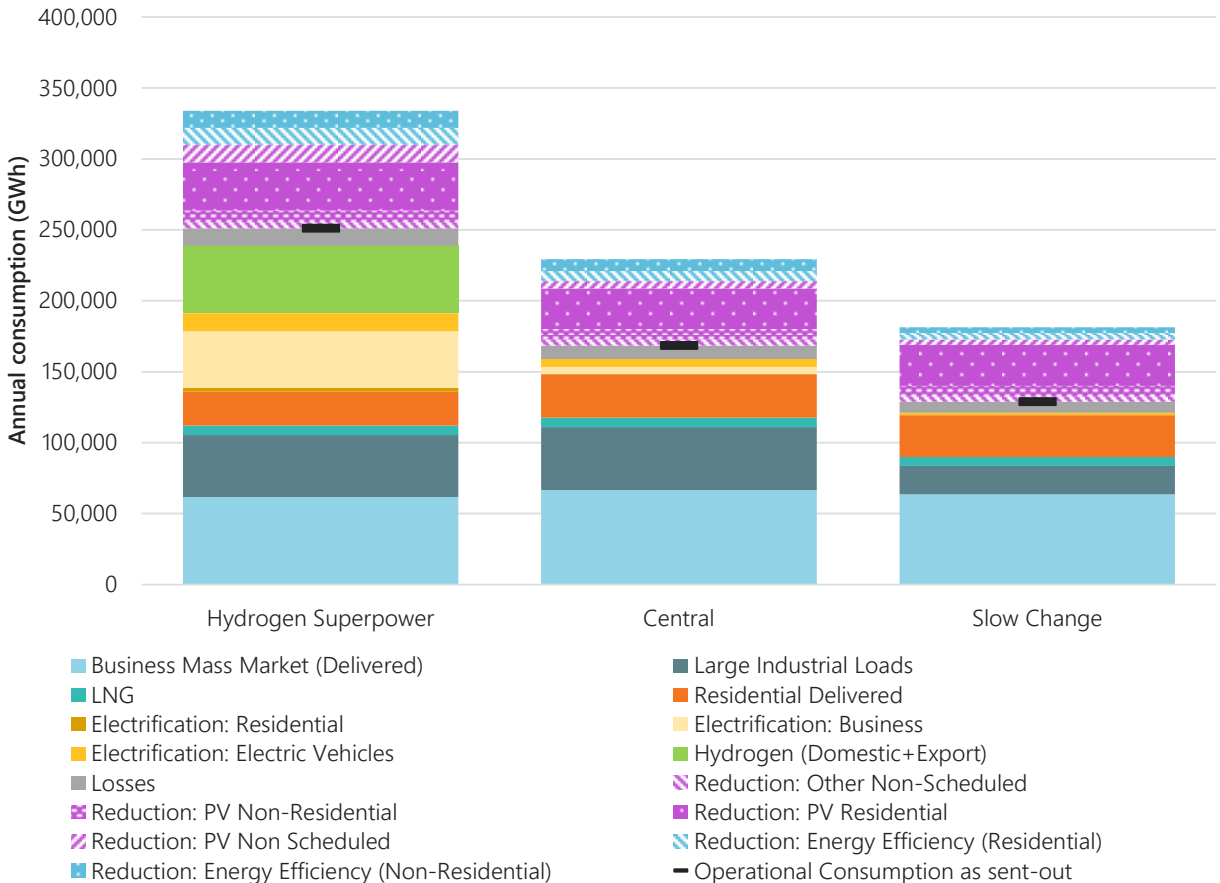


Figure 7 NEM consumption (by component) for the three ESOO scenarios in 2030-31



Note: Components that contribute to operational consumption are drawn in solid colours while those components reducing operational consumption drawn in shaded patterns, with the operational consumption forecast marking the dividing line.

Residential and residential EVs

Under the Central outlook, underlying residential consumption is forecast to increase from 57 TWh in 2020-21 to 59 TWh in 2030-31, due primarily to new household connections. Based on BIS Oxford dwelling construction forecasts, the number of household connections is forecast to increase from 9.3 million in 2020-21 to 10.8 million in 2030-31, and on average, each household is currently forecast to consume approximately 6 MWh annually.

Over time, average household consumption is projected to reduce, with energy efficiency improvements in appliances and building design, before starting to rise again following the electrification of heating load, hot water systems and uptake of EVs:

- By 2030-31, EVs are forecast to be cost-competitive with internal combustion engines, and between half a million and four million residential cars are projected to be electric, depending on scenario. This amounts to between 2% and 12% of additional residential consumption (up to 7 TWh).
- There is significant potential for residential sector electrification, particularly from gas space heating, some hot water heating, and a small impact from cooking and other appliances. In Victoria in particular, where many households rely on gas for heating, by 2030-31 residential sector electrification has the potential to increase consumption by up to 8% (or 5 TWh) by 2030-31 under certain scenario assumptions, with much of this consumption occurring over winter. This is discussed further in Section 6.3.

Residential consumption is expected to be heavily influenced by distributed PV generation. By 2030-31, production from distributed PV is expected to supply approximately 50-55% of the residential sector's overall consumption, depending on scenario. This represents approximately 4 million to 4.5 million homes generating to meet their own demand and at times exporting electricity to the grid.

Business – business mass market (BMM), large industrial loads (LILs), non-residential EVs, and liquified natural gas (LNG) sectors

Under the Central outlook, underlying business consumption (including BMM, LIL, and LNG) is forecast to increase from 128.8 TWh in 2020-21 to 139.5 TWh in 2030-31, due primarily to electrification of industry and transport and growth in the BMM (especially commercial) sector from 2025-26 onwards.

Key insights across the scenarios include:

- The BMM sector is forecast to decline slightly in 2021-22 following recent trends in usage, but is expected to grow from 78 TWh in 2020-21 to between 4 TWh and 12 TWh by 2030-31, due to projected commercial services economic growth.
- LILs, dominated by manufacturing and mining, show a similar aggregated outlook as last year, with no growth in the short term, and minor variance driven mainly by small changes in the operational outlook for several facilities. The Slow Change scenario, which considers the risk of several industrial closures, remains similar to the 2020 projection with LIL consumption forecast to fall by nearly 25% (or 25 TWh) by 2030-31 compared to 2020-21 consumption.
- LNG is expected to remain at stable levels of consumption (between 6 TWh and 7 TWh a year to 2030-31), although in the Hydrogen Superpower scenario the impacts of hydrogen exports taper demand for LNG.
- Electrification is one of the key differentiators in business consumption between scenarios by 2030-31. The key sectors that most strongly influence electrification of energy demand are expected to be transport (EVs) and industry, accounting for at least 90% of newly electrified loads in all scenarios. The varying influence of business sector electrification by 2030-31 is between 0.5 TWh and 45 TWh across the scenarios in Figure 7. The potential influence after 2030-31 is further explored in Section 6.3.
- In the Hydrogen Superpower scenario, domestic production of hydrogen from grid-connected electrolyzers is forecast to commence in 2024-25, adding approximately 4 TWh to business consumption by 2030-31. Export hydrogen and associated domestic steel production (green steel) is forecast to begin earlier in 2022-23, ramping up to approximately 58 TWh by 2030-31. Section 6.3 discusses these components in more detail and with a longer-term view.

- Mitigating a significant portion of this growth in consumption is energy efficiency. BMM and LIL sector energy savings of between 4 TWh and 12 TWh are forecast by 2030-31, reflecting the differing ambitions of the scenarios.
- Distributed PV uptake in the business sector, although smaller than in the residential sector, is forecast to continue growing. By 2030-31, distributed PV is forecast to meet nearly 10% of business sector consumption in all scenarios.

2.2 Annual operational consumption is moderated by the sustained uptake of DER

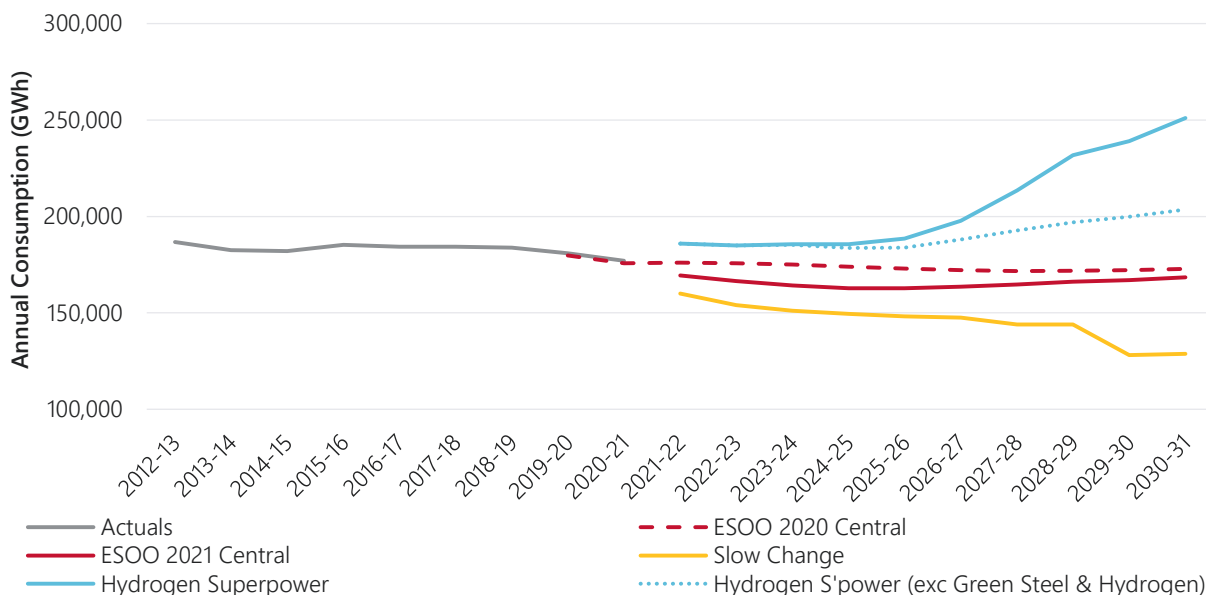
At the operational consumption level, demand for scheduled, semi-scheduled and significant non-scheduled generation is declining, with distributed PV being the largest factor driving reductions in forecast operational consumption in the next five years. The operational consumption forecasts shown in Figure 8 reflect the net impacts of the growth in underlying demand and distributed PV.

In the Hydrogen Superpower scenario, where electrification accelerates, growth could occur more quickly, with up to 55 TWh of new load by 2030-31 (representing approximately 25% of NEM 2020-21 underlying consumption). Domestic and export hydrogen and green steel has the potential to increase consumption by 2030-31 by an additional 48 TWh. Combined with other drivers of consumption growth, this represents nearly 125 TWh of additional underlying consumption, although due to strong distributed PV growth the impact on operational consumption a lower 73 TWh increase by 2031 (compared to 2020-21).

The Slow Change scenario, which features industrial closures and no electrification, forecasts a strong decline of 25 TWh of load by 2030-31 (approximately 15% of NEM 2020-21 consumption).

Figure 8 shows the trajectory of these different scenarios compared to the Central outlook, reflecting these differing growth drivers. These operational consumption forecasts are available to view or download from AEMO’s Forecasting Portal²⁹ and are further discussed in Appendices A1-A5.

Figure 8 NEM operational consumption, actual and forecast, 2012-13 to 2030-31, all ESOO scenarios



²⁹ At <http://forecasting.aemo.com.au/>.

2.3 Maximum operational demand forecasts remain steady

Maximum demand is influenced by the same drivers described in Section 2.1, however the forecast trend differs from the consumption trends (in Section 2.2) due to technology uptake impacting the load shape differently across the day.

The maximum demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including Reliability and Emergency Reserve Trader [RERT], the Wholesale Demand Response [WDR] mechanism, or DSP).

From this unconstrained demand forecast, the potential system needs for, and value of, these solutions can be identified. Non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained maximum demand forecasts presented in Figure 9.

AEMO prepares the forecasts as a distribution rather than single-point forecasts, given by the 10%, 50%, and 90% POE forecasts – see Section 1.2 for definitions, and Appendices A1-A5 for more detailed forecasts.

On the mainland, maximum operational demand typically occurs at the end of a hot summer day while houses and buildings retain their heat, and the distributed PV generation is low (see Figure 10). In Tasmania, where demand is dominated by heating, annual maximum demand typically occurs in winter mornings and evenings.

As the timing of maximum operational demand has pushed towards and past sunset, this has diminished the impact of distributed PV production on maximum operational demand. In the Central scenario over the next 10 years, the primary influences on maximum operational demand forecast trends are the residential and business drivers discussed in Section 2.1, such as new connections, the number of appliances being used, and how and when those appliances are used.

EV charging represents a weak driver of forecast maximum operational demand to 2030-31, contributing around 2% of maximum demand by 2030-31 in all NEM regions except Victoria, where EVs are expected to contribute to around 6% of maximum demand by 2030-31 primarily driven by state-based EV policy settings. Business sector electrification is forecast to have a minimal impact on maximum demand over the next decade for the Central scenario.

Electrification of transport and industry do have a greater influence on maximum operational demand in the next decade in the Hydrogen Superpower scenario and the Strong Electrification sensitivity, as discussed in Section 6.3.

Figure 9 shows the maximum operational demand forecasts for NEM regions under the Central scenario, and compares these to the equivalent 2020 ESOO forecasts, highlighting:

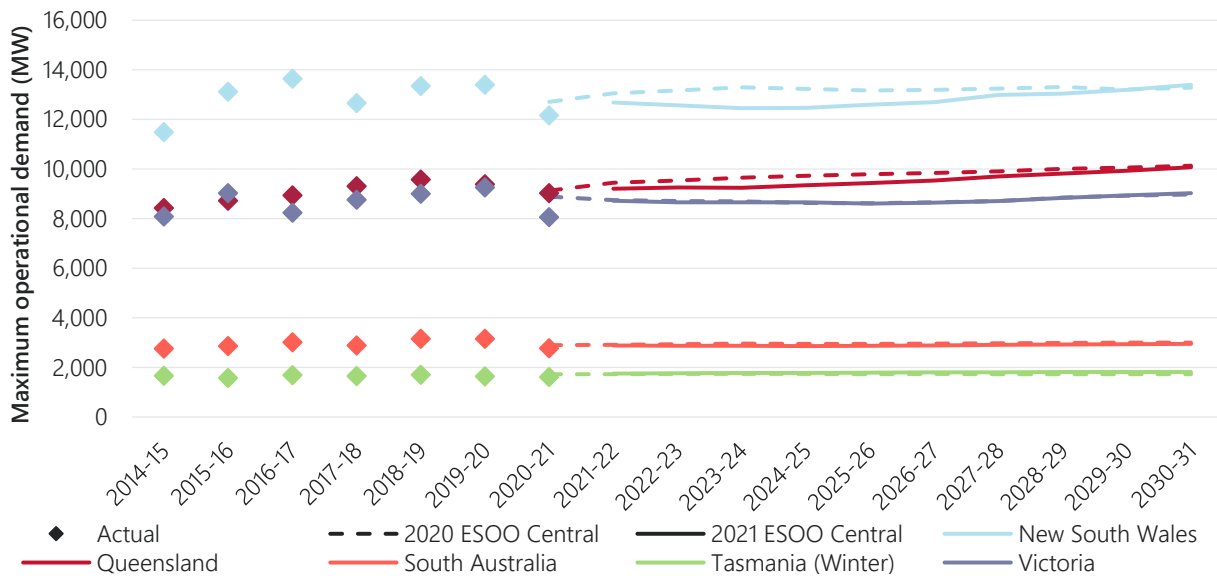
- In the short term, forecast maximum operational demand (50% POE) in the 2021 ESOO closely tracks the 2020 ESOO forecast in all regions except New South Wales.
- New South Wales maximum demand is forecast to dip in the short term from 2021-22 to 2024-25, due to lower BMM sector demand, until 2025-26, when it is forecast to resume growing.
- Queensland maximum demand is forecast to grow at a slightly higher rate than the other regions, driven by growth in both residential and business load.

Behind-the-meter batteries are not forecast to materially reduce maximum operational demand when uncoordinated, reducing the peak by around 1% or less by 2030-31. Coordinated battery charging and discharging, which is modelled explicitly in the supply adequacy assessment in response to dispatch signals, may help further reduce demand during maximum demand periods.

All NEM regions except Tasmania currently experience maximum operational demand late in the day, approaching twilight. To 2030-31, demand is expected to shift even later by about an hour to at, or just after, sunset in these regions, due to uptake of distributed PV capacity.

Appendices A1-A5 discuss forecasts for each region and scenario.

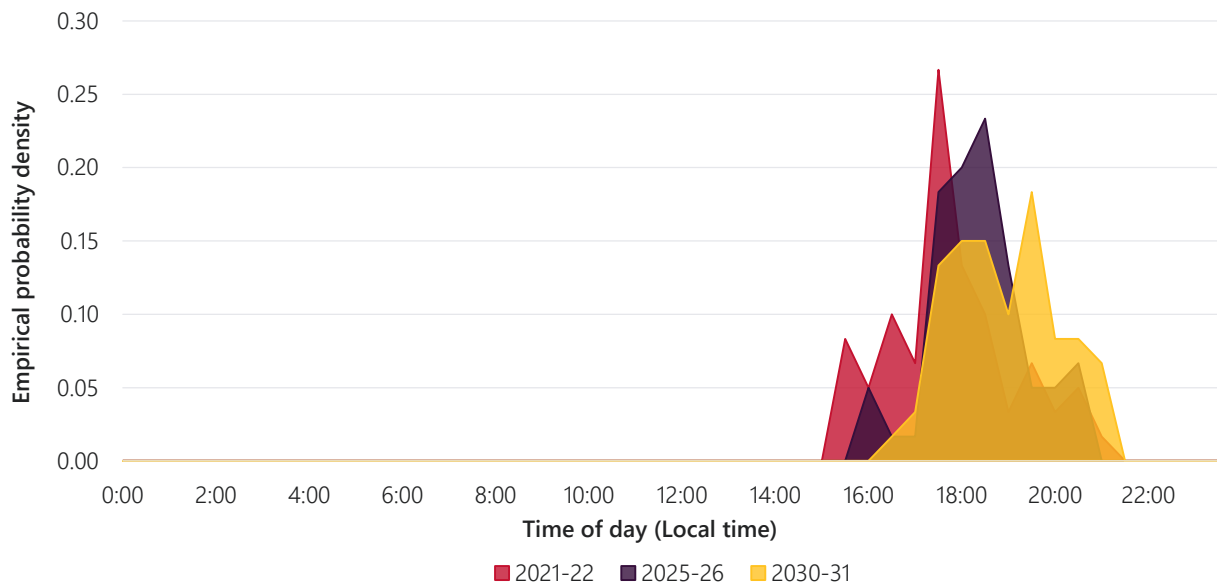
Figure 9 Regional summer (winter for Tasmania) actual and forecast 50% POE maximum operational demand (sent out), 2021 ESOO Central and 2020 ESOO Central scenarios, 2014-15 to 2030-31



Note: The actuals displayed are not weather-corrected and exclude DSP.

Figure 10 illustrates the Central scenario forecast distribution of time of maximum operational demand for New South Wales to demonstrate this trend to later peaks. New South Wales is representative of the other mainland regions, although the timing of maximum demand events in South Australia and Victoria is forecast to be more tightly distributed around 8.00 pm local time by 2030-31 (due to high distributed PV penetration). Maximum operational demand in Tasmania typically occurs in winter, with both morning and evening maximum operational demand events possible just before business hours or just after.

Figure 10 Central forecast showing change in distribution of time of 50% POE summer maximum demand in New South Wales, 2021-22 to 2030-31



2.4 Minimum operational demands forecast to rapidly decline

Minimum operational demand is influenced by the same drivers described in Section 2.1.

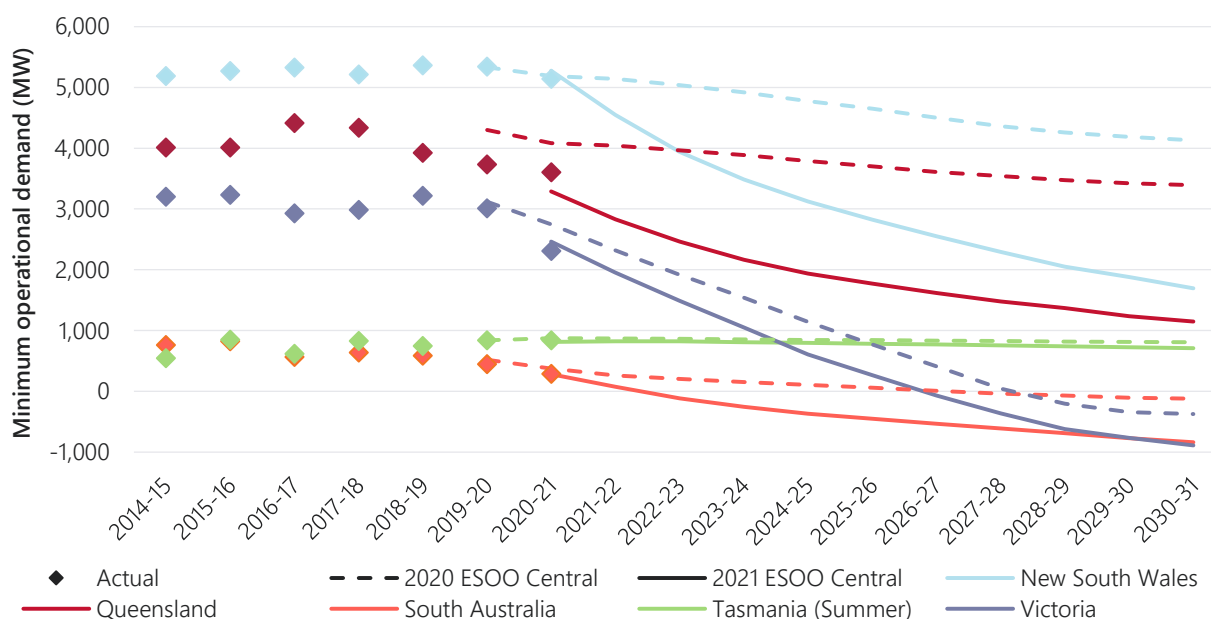
The strongest influence is distributed PV uptake, which drives a rapid decline in demand for scheduled, semi-scheduled, and significant non-scheduled generators during periods of low underlying demand.

The minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase operational demand (including storage, coordinated EV charging, scheduled loads such as pumping load, and demand response) in periods of excess supply. Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained minimum demand forecasts presented in Figure 11.

AEMO prepares the forecasts as a distribution rather than single-point forecasts, given by the 10%, 50%, and 90% POE forecasts – see Section 1.2 for definitions, and Appendices A1-A5 for more detailed forecasts.

Figure 11 compares the 2020 ESOO and 2021 ESOO 50% POE minimum demands for each region. Differences compared to the 2020 ESOO are primarily driven by higher distributed PV uptake trajectories this year.

Figure 11 Regional annual (summer for Tasmania) actual and forecast 50% POE minimum operational demand (sent out), 2021 ESOO and 2020 ESOO, Central scenario, 2014-15 to 2030-31



Note: The actuals displayed are not weather-corrected and exclude correction from DSP.

Due to the continued high uptake of distributed PV, and consistent with historical observations, each NEM region on the mainland is forecast to experience minimum demand in the middle of the day from now on. This shift has been witnessed in recent times, with around three-quarters of annual minimum demand events in these regions occurring between 12.00 pm and 2.30 pm local time since 2018-19.

Tasmania is an exception; while it has had several midday minimums, these minimum demand events were driven by reduction in LILs, which contribute approximately 75% to Tasmania’s minimum demand. Moving forward, minimum demand is forecast to occur in the middle of the day in Tasmania.

There are potential market-based solutions to increase operational demand in the daytime. These mechanisms include coordinated charging of storage (both distributed and grid-scale), coordinated EV charging, and demand response. These have not been included in the minimum operational demand forecasts presented in the 2021 ESOO, but are modelled to respond to dispatch signals in the supply adequacy assessments.

In these minimum operational demand forecasts to 2030-31:

- In the short term, minimum demand in NEM mainland regions is forecast to decline rapidly, due to the forecast higher uptake of distributed PV capacity compared to the 2020 ESOO. For several regions, this accelerates the need for complementary market-based and operational support earlier than forecast in the 2020 ESOO (further discussed in Section 6.1).

- Minimum demand in Tasmania is not forecast to decline to nearly the same extent as mainland regions, due to much lower forecast distributed PV capacity uptake and proportionately more business load.
- Towards 2030-31, the decline in minimum demand is expected to be subdued, as demand during minimum demand times is projected to be increased by:
 - EVs – growth is forecast to pick up from the late 2020s and early 2030s. EVs are also forecast to gradually shift away from pure convenience charging towards day charging patterns that better complement generation from distributed PV.
 - Batteries – capacity is forecast to increase and is assumed to shift from convenience charging to periods complementing distributed PV generation.

While there is a general trend for minimum demands to be more prevalent during the middle of the day, there remains some uncertainty regarding the level these minimums reach. Factors such as prevailing weather conditions, demand from LILs, and the operation of non-scheduled generation all influence the distribution of minimum demand outcomes and their time of occurrence.

2.5 Demand side participation forecasts remain similar to previous forecasts

For the 2021 ESOO, AEMO updated its estimate of DSP (also referred to as demand response) responding to price and reliability signals, including any contribution from WDR. The estimates are based on information provided to AEMO by all registered market participants about the DSP portfolios as of April 2021, using the methodology described in AEMO's *DSP Forecasting Methodology Paper*³⁰. DSP is forecast to remain at a similar level as forecast in 2020, with 684 MW of DSP projected across the NEM (see Table 4).

Table 4 Estimated DSP responding to price or reliability signals, summer 2021-22

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	18	22	4	9	3
> \$500/MWh	42	41	12	26	42
> \$1,000/MWh	45	41	14	26	50
> \$2,500/MWh	52	41	18	26	61
> \$5,000/MWh	66	41	23	26	63
> \$7,500/MWh	66	45	33	26	65
Reliability response	308	104	33	26	212

The ESOO only includes existing and committed sources of DSP, consistent with the treatment of generation and transmission developments. The Table 4 estimates of reliability response have been used for the 10-year horizon of the ESOO³¹. The DSP forecast excludes the New South Wales peak demand reduction scheme, which has not yet been formally committed. Appendix A6 provides further DSP forecast details and statistics³².

³⁰ At <https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation>.

³¹ AEMO does not have visibility of any further committed DSP sources beyond those included in Table 4.

³² To fulfil the requirements under NER 3.13.3A(a)(8) and NER 3.7D (d).

3. Supply forecasts

The capability of the power system to generate and securely transmit energy to consumers is a key input assumption to the supply adequacy assessment in the 2021 ESOO. This chapter outlines the supply forecasts for the next 10 years, including:

- Generator commissioning and decommissioning assumptions.
- Seasonal generator capacities and reliability.
- Transmission developments.

3.1 Generation changes in the ESOO

The supply adequacy assessment in the 2021 ESOO considers existing and new generation, storage, and transmission projects that either meet, or are highly likely to meet, AEMO's commitment criteria.

This data is published on AEMO's Generation Information web page, and is provided to AEMO by both NEM participants and generation/storage project proponents.

The 2021 ESOO assessment includes committed and anticipated transmission projects (see Section 3.5) and generation and storage projects currently³³ classified as:

- **Existing generation and storage plant.**
- **Committed projects** – these projects meet all five of AEMO's commitment criteria³⁴.
 - Committed projects are assumed to become available for full commercial operation on dates provided by participants, with commissioning profiles added only where operational data indicates the project is ahead or behind the schedule provided.
- **Committed* projects** – these projects are under construction and well advanced to becoming committed³⁵.
 - Committed* projects are assumed to commence operation after the end of the next financial year (1 July 2023), reflecting uncertainty in the commissioning of these projects. For further details, see AEMO's *ESOO and Reliability Forecast Methodology Document*³⁶.

Generation retirements are considered to occur on dates provided by participants, either with precision under the three-year notice of closure rules, or on 31 December of the provided expected closure year.

³³ AEMO, Generation Information, 13 July 2021 update, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

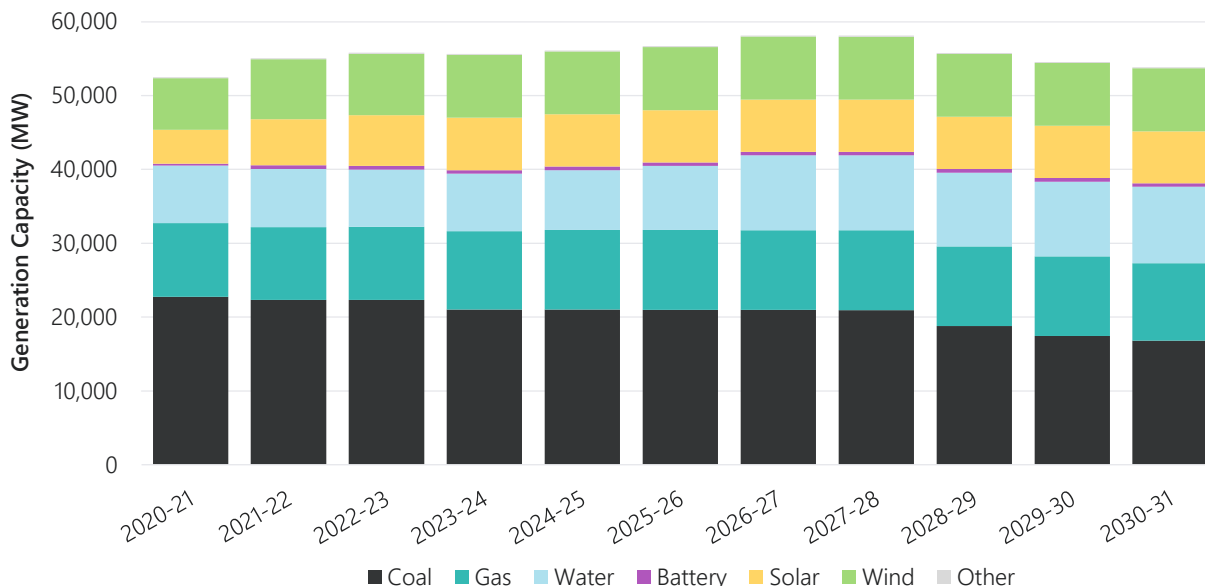
³⁴ Commitment criteria relate to land, contracts, planning, finance, and construction. For details, see the Background Information tab on each spreadsheet at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

³⁵ In AEMO's Generation Information page these projects are called Committed* or Com*. They are projects that are highly likely to proceed, satisfying the land, finance and construction commitment criteria, plus either of the planning or contracts criteria. Progress towards meeting the final criterion is evidenced, and construction or installation has also commenced.

³⁶ See Section 2.6. at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

Figure 12 shows the Summer Typical capacity (the capability of the generating unit during average summer temperatures) assumed per forecast year in the 2021 ES00, considering the specified commissioning and decommissioning profiles of generation and storage.

Figure 12 Assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31



Source: AEMO’s Generation Information publication: January 2021 version for 2020-21 data and July 2021 version for 2021-22 to 2030-31. At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

As shown in Figure 12, large amounts of new generation capacity continue to connect in the NEM. An additional 2,245 megawatts (MW) of new capacity is forecast to be operational this summer, compared to what was forecast to be available last summer. This includes 470 MW of dispatchable battery storage capacity.

In addition to the 2.2 GW of new capacity expected to connect for the coming summer, a further 2.2 GW of new capacity is forecast to become operational within the next five years, including the following dispatchable projects:

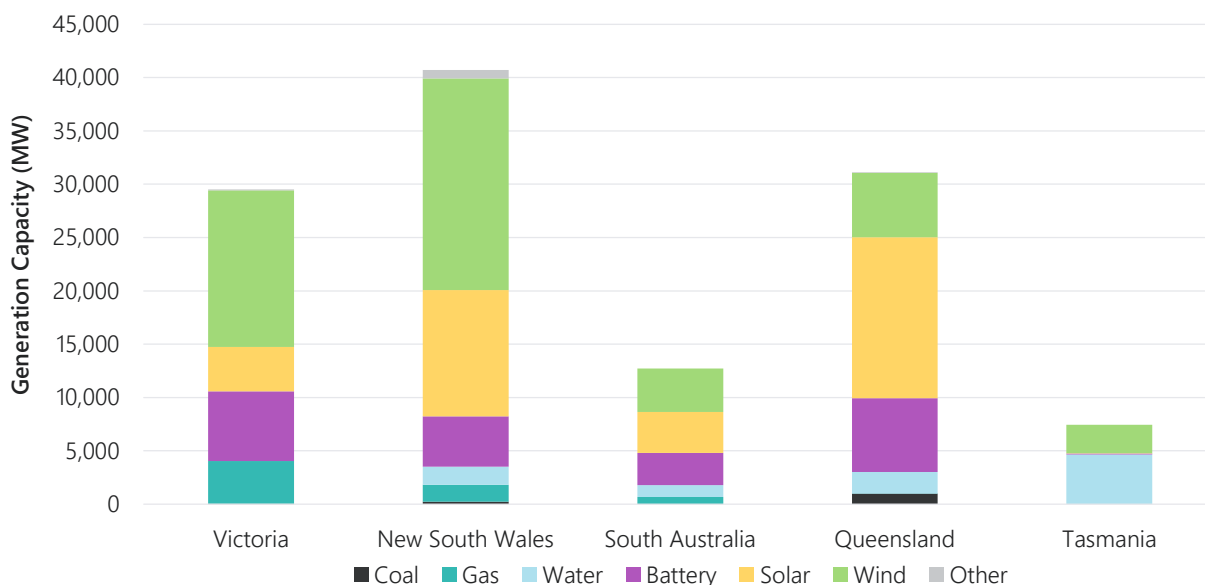
- The 750 MW Kurri Kurri Power Station is now expected to be operational by 2023-24, partially replacing capacity lost with the retirement of the 2,000 MW Liddell Power Station in New South Wales over the 2022 and 2023 calendar years.
- The 154 MW Snapper Point Power Station (previously South Australia Temporary Generation North) is now modelled to be operational by 2023-24, partially replacing capacity lost with the 2023 retirement of the 180 MW Osborne Power Station in South Australia.
- The 250 MW Kidston Pumped Hydro Energy Storage project is now planned to commence operations in Queensland in 2024-25.

3.2 Pipeline of future projects

Beyond those projects already Committed or Committed*, there is a substantial pipeline of future projects in various stages of development, from publicly announced to anticipated stages of planning. These projects total 121 GW and are spread across all regions, with the largest pipeline of capacity in New South Wales.

Figure 13 shows the current pipeline by region and type of generation, beyond already committed projects.

Figure 13 Proposed projects by type of generation and NEM region, beyond those already committed



Source: July 2021 Generation Information, at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

Key points about this pipeline are:

- By capacity, over 67% of future projects currently tracked by AEMO are variable renewable energy (VRE) generation projects, and over 25% are battery storage or pumped hydro projects.
- Approximately 23 GW of additional dispatchable capacity – including thermal generation, pumped hydro generation, and batteries – has been added to the pipeline of future projects over the past year, a significant increase from the pipeline of 4 GW of dispatchable capacity reported in the 2020 ESOO.
- Of the 121 GW of future projects, over 2 GW are reported as being in more advanced stages of development and are classed as ‘Anticipated’³⁷ – these projects are not included in the ESOO, but will be included in the 2022 ISP.

Further details, including capabilities of proposed generating units, are on the Generation Information page.

Instantaneous renewable generation penetration

Figure 14 shows the indicative potential impact of existing, committed and anticipated new generation capacity on instantaneous renewable generation penetration. Instantaneous renewable generation penetration represents the proportion of underlying demand in a dispatch period that is met by renewable resources (large-scale wind, solar, hydro, biomass and distributed PV). Between 2018-19, and 2020-21, instantaneous renewable generation penetration increased markedly, with a record of 57% in 2020-21³⁸.

Based on the indicative resource potential of all committed and anticipated projects, AEMO forecasts that there would be sufficient renewable resources to supply all NEM underlying demand in some periods by 2024-25, as also shown in Figure 14. That is, 100% instantaneous renewable generation penetration, assuming no network or system security limitations. A high proportion of this renewable generation could be from inverter-based resources (IBR – wind and solar generation, including distributed PV).

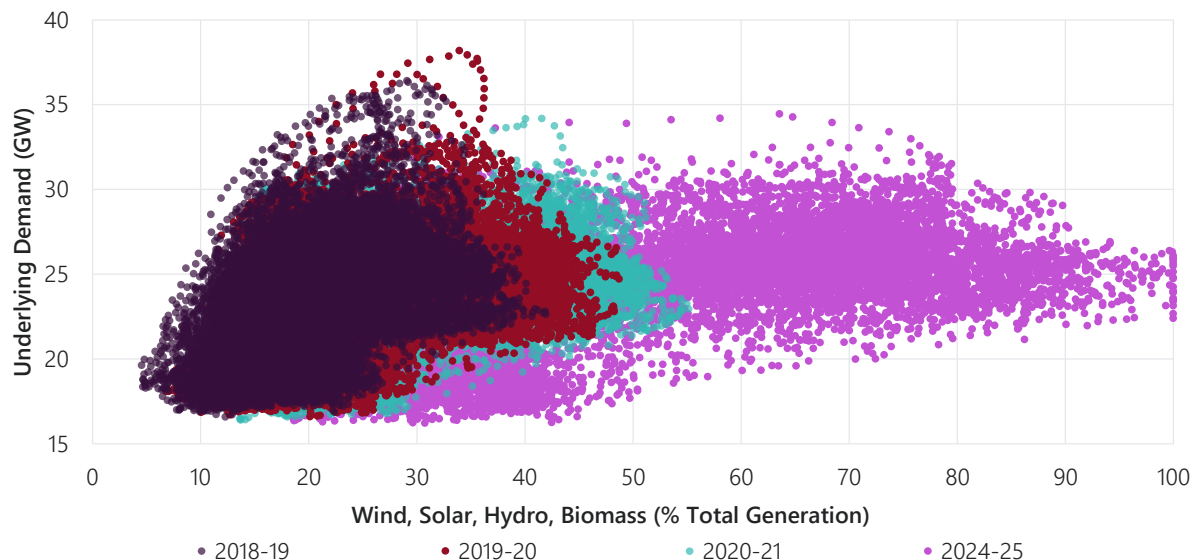
With AEMO’s current operating toolkit, it would not be possible to maintain the power system securely under these conditions, which is why AEMO has the goal to engineer the power system to be capable of operating securely through these periods of high instantaneous penetration of renewable energy.

³⁷ Anticipated projects are those that are sufficiently progressed towards meeting at least three of the five commitment criteria used by AEMO to determine commitment status. Typically, anticipated projects are included in integrated system planning, but not in reliability assessments.

³⁸ See AEMO, *Quarterly Energy Dynamics Q2 2021*, at <https://aemo.com.au/-/media/files/major-publications/qed/2021/q2-report.pdf>.

AEMO's recent *Advanced Grid-Scale Inverter White Paper*³⁹ looked in detail at technological opportunities to enable secure system operation during periods of high instantaneous penetration of IBR. Operational implications and emerging solutions to maintain secure operations during high penetration of DER (a subset of this broader challenge) are discussed further in Chapter 6 of this ES00.

Figure 14 NEM-wide penetration of renewable resources (large-scale and distributed), 2018-19 to 2020-21, with indicative resource potential forecast for 2024-25 based on existing, committed, and anticipated projects and distributed PV forecasts



3.3 Seasonal generator availability

AEMO collects existing and committed scheduled and semi-scheduled generation capabilities over the next 10 years to capture seasonal generator availability⁴⁰. Scheduled capacity values are collected for three seasonal periods, where generator operators and proponents provide ratings consistent with the ambient temperatures associated with the following periods:

- Summer peak – applies to near-maximum demand periods (minimum of five days per year), where generator ratings are reflective of the ambient conditions associated with 10% POE demand events.
- Summer typical – aligned with average summer temperatures and is applied in all other summer periods (November – March for the Australian mainland, December – February for Tasmania).
- Winter – applied to all non-summer periods.

The same seasonal ratings are applied to VRE generators, with additional consideration given to resource availability. The ratings have been provided by registered participants and are reported in the July 2021 Generation Information page⁴¹.

Figure 15 shows the average winter, summer typical, and summer peak availability relative to nameplate capacity by type of generation (both existing, Committed and Committed*), and indicates the reduced availability reported in summer peak compared to winter and summer typical. This is especially noticeable for wind generators, due to some reporting 0 MW availability during summer peak, reflecting high-temperature cut-offs for this generation category.

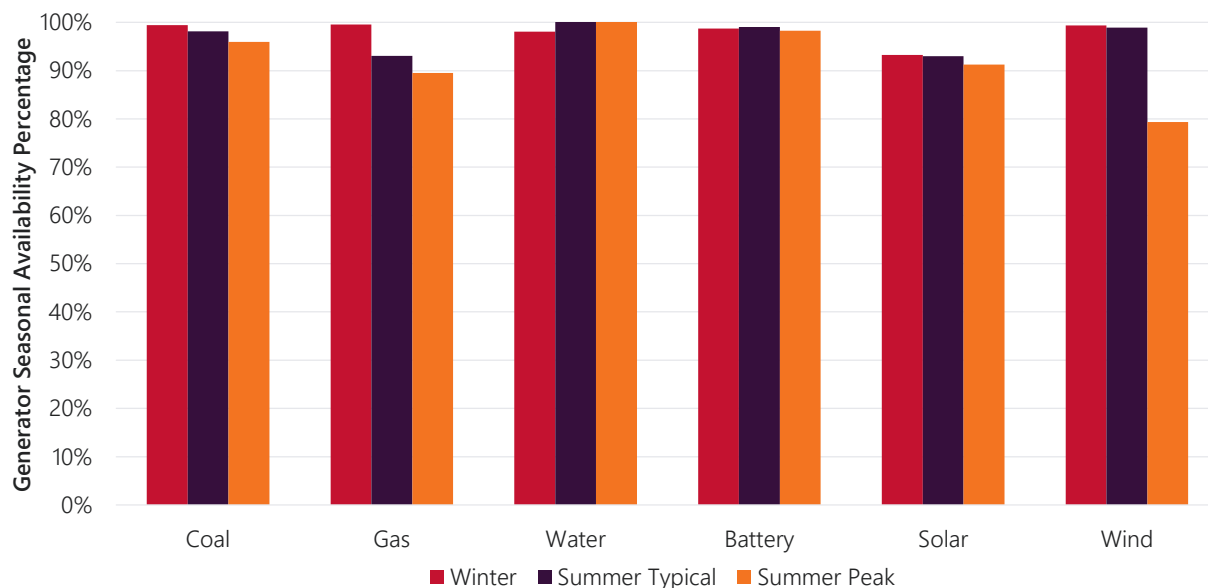
³⁹ At <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf>.

⁴⁰ See Generation Information, 13 July 2021 update, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁴¹ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

See the *ESOO and Reliability Forecast Methodology Document*⁴² for more detail about generation availability.

Figure 15 Winter, summer typical and summer peak availability percentage of nameplate capacity by type of generation



3.4 Generator forced outage rates

AEMO collects information from all generators via an annual survey process on the timing, duration, and severity of historical forced outages. Observed forced outages of duration in excess of five months are classified as long duration outages and are assessed separately.

The historical data is then used to calculate the observed rate of long duration, full, and partial forced outages for each financial year, for each generator. Excluding coal-fired and large gas-fired generators, the rates calculated from observed incidents have been used as projections in the 2021 ES00 for each generator.

Future trends in generation outage rates are uncertain, and are likely to change as generators age, approach retirement, and go through maintenance cycles. In addition to historical data, AEMO collects forward-looking forced outage rate projections from the operators of coal-fired and large gas-fired generators. In a small selection of instances where operators were unable to provide a full set of future projections, AEMO adopted forward-looking outage rates commissioned in 2020 from AEP Elical⁴³.

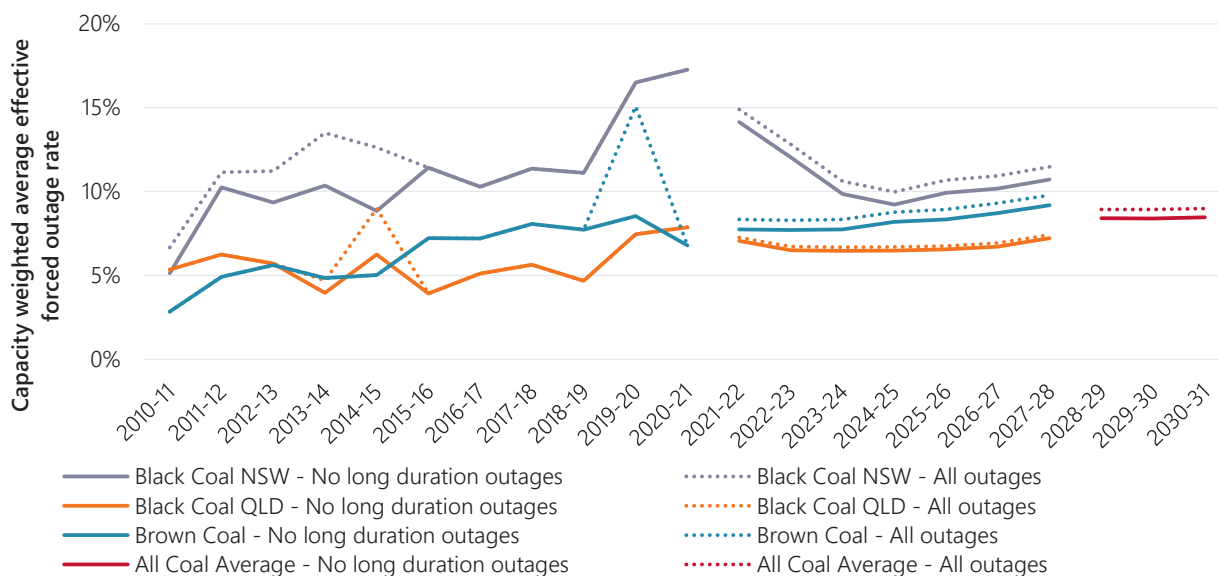
Coal-fired generation reliability continued to deteriorate last year, consistent with recent historical trends. While some improvements to plant are expected in the near term, most generators are anticipating a trend of decreasing reliability in the longer term.

Figure 16 shows the historical and projected effective forced outage rates for coal-fired generators (aggregated to protect the confidentiality of information provided by participants). These rates are shown with and without long duration outage rates of five months or more.

⁴² See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

⁴³ AEP Elical, *Assessment of Ageing Coal-Fired Generation Reliability*, June 2020, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

Figure 16 Effective full forced outage rate projections for coal-fired generation technologies



The IASR Assumptions Book provides detailed information on the forced outage rate parameters of each technology over time⁴⁴.

3.5 Transmission limitations

The ESOO model applies 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 constrain generation, but also frequently limit interconnector transfer capacity. AEMO also applies transmission outage constraints for simulated unplanned outages (see the 2021 IASR for more details⁴⁵).

The 2021 ESOO modelling includes committed and relevant anticipated transmission augmentations in the Central scenario⁴⁶ as described below.

Inter-regional augmentations included in the 2021 ESOO – committed and anticipated

- Victoria to New South Wales Interconnector (VNI) System Integrity Protection Scheme (SIPS)** by November 2021. Allows increased import capability from New South Wales to Victoria during November to March each year. This involves procurement of a 250 MW SIPS in Victoria to rapidly respond by injecting power after a contingency event on VNI. AEMO has tested the reliability impact of any potential delay to this scheme, following a fire at the Victorian Big Battery. See Section 4.3 for more details.
- Queensland New South Wales Interconnector (QNI) Minor** by July 2022. Involves upgrading of Liddell – Tamworth, Liddell – Muswellbrook and Muswellbrook – Tamworth 330 kilovolt (kV) transmission lines, installation of shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations, and installation of dynamic reactive plant at Tamworth and Dumaresq.

⁴⁴ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

⁴⁵ See Section 3.10.10, at <https://www.aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en>.

⁴⁶ For the purposes of the ESOO, transmission augmentations are included in accordance with AEMO’s *ESOO and Reliability Forecast Methodology Document*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

- **VNI Minor** by September 2023. Involves upgrading of the South Morang – Dederang 330 kV line, installation of an additional 500/330 kV transformer at South Morang, and addition of power flow controllers on the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV lines.
- **Project EnergyConnect⁴⁷ by June 2025**. Involves construction of new double-circuit 330 kV transmission lines between Robertstown, Buronga, Dinawan and Wagga Wagga, and an additional 220 kV line between Red Cliffs and Buronga. It has completed its regulatory approval process, and received expenditure approval from the Australian Energy Regulator (AER) in May 2021. To allow for inter-network testing, Project EnergyConnect is modelled with its full capacity available from June 2025.

Intra-regional augmentations included in the 2021 ESOO⁴⁸ – recently developed, committed and anticipated

- **New South Wales (see TransGrid’s 2020 Transmission Annual Planning Report⁴⁹):**
 - Powering Sydney – a new 330 kV cable between Beaconsfield and Rookwood Road by November 2021.
 - Powering Sydney – changing Beaconsfield – Sydney South cable operating voltage from 330 kV to 132 kV by March 2022.
 - Installation of capacitor bank at Wagga Wagga substation by May 2022.
- **Queensland (see Powerlink’s 2020 Transmission Annual Planning Report⁵⁰):**
 - Gin Gin substation rebuild (in service).
 - Calvale 132 kV network reconfiguration (in service).
 - Strathmore substation additional 275/132 kV transformer by March 2023.
 - Lilyvale substation replacement of 2 x 80 megavolt-amperes (MVA) 132/66 kV transformers with 2 x 160 MVA 132/66 kV transformers by September 2024.
- **South Australia (see ElectraNet’s 2020 Transmission Annual Planning Report⁵¹):**
 - South Australia Power System Strength Project, installation ongoing. Involves installation of two high inertia synchronous condensers at Davenport and two high inertia synchronous condensers at Robertstown.
 - Eyre Peninsula Link, by November 2022. Replacement of the existing 132 kV lines between Cultana and Yadnarie with a new double-circuit line that is initially energised at 132 kV, with the option to be energised at 275 kV in the future. Replacement of the existing 132 kV line between Yadnarie and Port Lincoln with a new double-circuit 132 kV line.
 - Power flow controller on the Templers – Waterloo 132 kV line (in service).
- **Tasmania (see TasNetworks’ 2020 Transmission Annual Planning Report⁵²):**
 - Burnie – Port Latta – Smithton 110 kV line reconfiguration by November 2021.
- **Victoria (see AEMO’s 2020 Victorian Transmission Annual Planning Report⁵³):**

⁴⁷ This project is treated as Anticipated for the purpose of the 2022 ISP.

⁴⁸ The Central West Orana renewable energy zone (REZ) transmission link is an anticipated network project under the 2021 IASR, but is excluded from the 2021 ESOO modelling as its transmission augmentation components would not be impactful on the modelling undertaken for the ESOO.

⁴⁹ At <https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf>.

⁵⁰ At <https://www.powerlink.com.au/reports/transmission-annual-planning-report-2020>.

⁵¹ At <https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf>.

⁵² At <https://www.tasnetworks.com.au/Documents/Manual-documents/Planning-and-upgrades/APR/Annual-Planning-Report-2020>.

⁵³ At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.

- Western Victoria Transmission Network Project (Stage 1). Upgrading of Moorabool – Terang and Ballarat – Terang 220 kV lines (in service). Upgrading of Red Cliffs – Wemen – Kerang – Bendigo transmission lines (by August 2021).
- Western Victoria Transmission Network Project⁵⁴ (Stages 2 and 3) is estimated to be delivered by October 2025, with any final inter-network testing completed by July 2026. Stage 2 involves installation of a new 500 kV double circuit transmission line from Sydenham to the new terminal station north of Ballarat and a new 220 kV double circuit line from north of Ballarat to Bulgana, and a range of supporting works. Stage 3 involves completion of any inter-network testing.
- Power flow controller on the Wodonga – Jindera 330 kV line (in service).
- Shunt reactors at Keilor and Moorabool terminal stations between April 2021 and March 2022.

⁵⁴ For more information see <https://www.westvictnp.com.au/>. This project is treated as Anticipated for the purpose of the 2022 ISP.

4. Supply scarcity risks this summer

This chapter discusses supply scarcity risks in the coming 2021-22 summer, and reports:

- Overall risks under normal conditions are relatively low.
- Neither the extended outage of Callide C Unit 4 (following the operating incident that occurred in May 2021) nor the recent fire at the Victorian Big Battery are likely to cause material reliability implications.
- Potentially significant flooding at the Yallourn Power Station could lead to prolonged periods of supply scarcity in Victoria this summer.
- This and other risks could result in the need for mitigation actions, such as the use of RERT.

4.1 Supply scarcity risks are mostly lower than previously forecast

The central reliability outlook for the coming summer indicates relatively low reliability risks are expected in all regions. For most regions, the risk is lower than previously forecast. This reduction is driven by reduced peak demand and energy consumption forecasts (see Chapter 2), and the large amounts of new generation, storage, DER, and transmission capacity that continue to connect to the NEM (see Chapter 3).

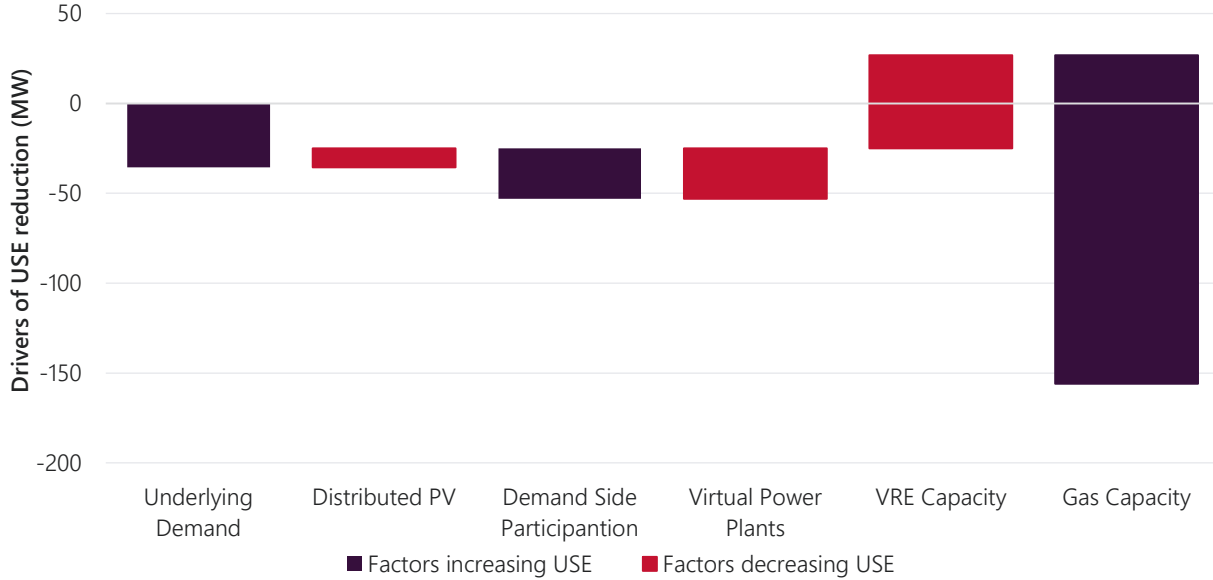
While reliability in all regions is forecast to be below the IRM, the nature of the reliability risk varies by region:

- In **Tasmania, Queensland, and New South Wales**, the supply scarcity risk is negligible in summer 2021-22, with expected USE well below 0.0006% of annual consumption. In New South Wales, the supply scarcity risk for next summer is slightly lower than AEMO had previously forecast. While projected generator forced outages are higher, this is more than offset by decreases in forecast maximum operational demand.
- In **Victoria**, on average, 99.9998% of annual consumption is expected to be met this summer. The reliability forecast is relatively similar to the 2020 ESOO outlook and continues to be below the IRM, where slight increases in demand and increased coal forced outage rates are offset by the expected commissioning of the Victorian Big Battery⁵⁵, and associated increases in the VNI transfer capacity. This increased transmission capacity is relatively well utilised due to low levels of peak demand coincidence between Victoria and New South Wales.
- In **South Australia**, the reliability forecast for next summer has worsened slightly relative to the 2020 ESOO outlook, primarily due to the announced mothballing of one Torrens Island B unit, although the supply scarcity risk continues to be below the IRM. Figure 17 shows the drivers of variation in the 2021-22 forecast of USE for South Australia, where negative values represent drivers towards increasing USE, while

⁵⁵ See 4.3 for the results of a sensitivity that tests the implications of commissioning delays at the Victorian Big Battery following the recent fire.

positive values represent drivers lowering USE. In this case, the largest driver of the USE change is the reduction in gas capacity, as expected given the Torrens Island B unit mothballing.

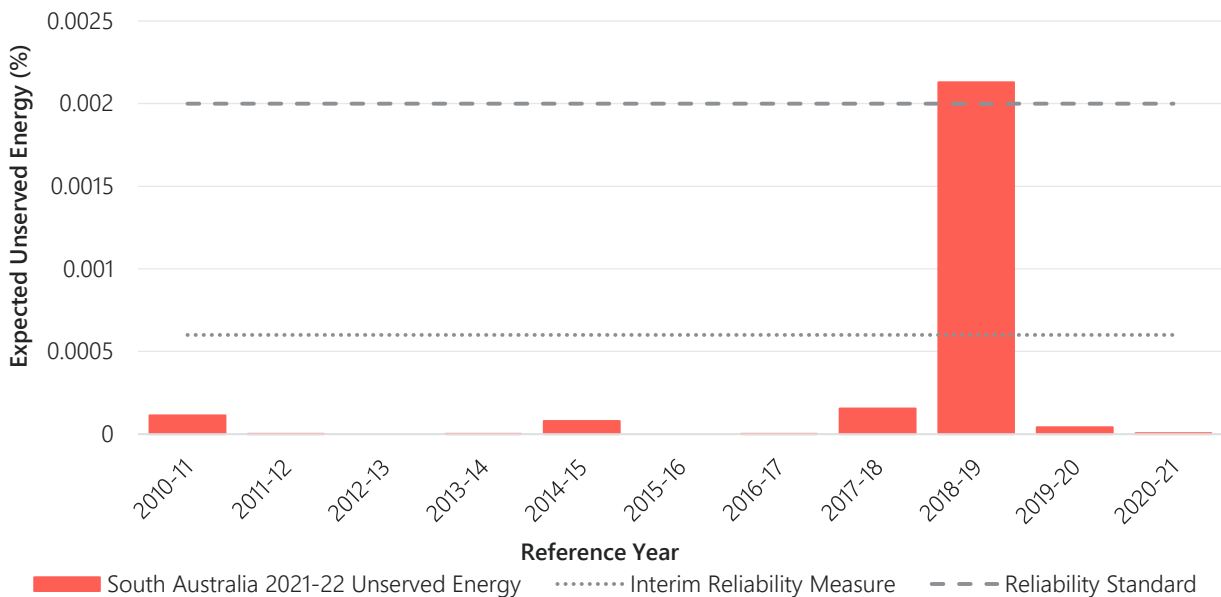
Figure 17 Indicative drivers of change in expected unserved energy in South Australia in 2021-22 (2021 ESOO forecast versus 2020 ESOO forecast)



Outcomes vary greatly depending on weather conditions: South Australia example

Figure 18 shows the level of expected USE forecast in South Australia for the 2021-22 summer in each of the historical reference years modelled. Historical reference years are used to model the impact of weather conditions in time-series on wind generation, solar generation, consumer demand patterns, high temperature periods for thermal plant deratings, and some transmission line ratings (those with dynamic line ratings). Variation in expected USE between reference years is due to the relative contribution of VRE during times of high demand, the level of coincidence in demand between regions, or the length of time demands were at near-peak levels, during those years.

Figure 18 Impact of different reference years on expected USE in South Australia 2021-22, Central scenario



The chart shows that under the weather conditions associated with the 2018-19 reference year, the forecast level of expected USE next summer would exceed both the IRM and the reliability standard. The 2018-19 reference year contains the highest maximum temperature ever recorded for Adelaide Airport (45.8°C on 24 January 2019) coinciding with close to record-level temperatures in Victoria, resulting in high electricity demands across both regions during low VRE conditions. This low VRE output, as observed and modelled, incorporates any potential impact of high temperature deratings

The newly added 2020-21 reference year, which was a relatively mild summer without frequent high temperature periods that could cause derating, is characterised by below average VRE availability throughout the year but average levels of VRE availability during high demand periods.

4.2 Risks of flooding at the Yallourn Power Station in Victoria

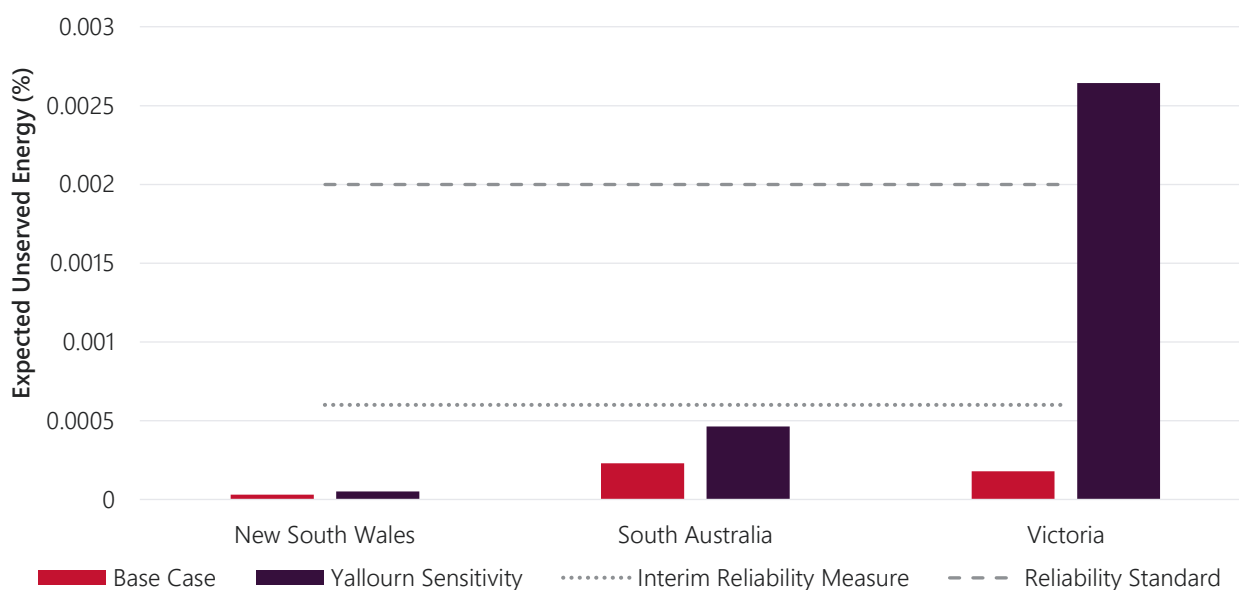
Despite the Central reliability forecast indicating that expected USE is below both the reliability standard and the IRM, there remain numerous factors that could pose a reliability concern in the coming summer.

The largest risk identified this summer is the potential unavailability of the Yallourn Power Station in Victoria. Recent flooding in the Morwell River diversion through the coal mine created cracks in the mine wall, putting it at greater risk of flooding during future heavy rainfall events. If the mine were to flood in a significant rainfall event, indications are it could take 12-18 months to recover. While the likelihood of such an event is relatively low, the consequence could be significant if risk mitigations are not in place.

AEMO has completed a sensitivity analysis that projects expected USE under a circumstance where this flooding event occurs in October 2021, resulting in the full unavailability of the Yallourn Power Station for summers 2021-22 and 2022-23. This sensitivity further assumed that the decision to mothball Torrens Island B1 is reversed in response to this disaster, and the Snapper Point Power Station is prioritised for commissioning prior to summer 2021-22⁵⁶, limiting the impact in South Australia.

Figure 19 shows the results of this sensitivity in 2021-22, comparing USE to the base case and highlighting that expected USE in Victoria exceeds both the IRM and the reliability standard. Notably, should such an event occur, AEMO forecasts a risk to between 150,000 and 500,000 households in Victoria being without power for up to eight hours during an extreme heat event (that is, a 1-in-10 year peak demand event) at least once this summer.

Figure 19 Yallourn mine flooding sensitivity, impacts on USE in 2021-22



⁵⁶ This project is considered Committed* so it is not included in the Central scenario until July 2023.

Results for 2022-23 are not shown but are slightly lower (0.0021% USE in Victoria), due to reduced demand expectations and additional committed supply.

AEMO is working with the Victorian Government to explore options that could help mitigate this risk.

4.3 Potential Victorian Big Battery commissioning delay

Another factor that could pose a reliability concern is delayed commissioning of expected new connections. On 30 July 2021, a fire broke out at the Victorian Big Battery which is yet to be fully commissioned. The scale of the damage, and any impact on commissioning schedules, is yet to be determined. The Victorian Big Battery is included in the ESOO base case for this summer as it is a committed project. Additionally, the Victorian Big Battery is contracted to provide services as part of the VNI SIPS.

A sensitivity was developed to test the potential impact if commissioning of the battery was delayed and the battery was not available through the summer period (1 November 2021 to 31 March 2022). Unlike the Yallourn flooding sensitivity, this sensitivity did not assume the reversal of AGL’s decision to mothball Unit 1 of Torrens Island B, nor did it assume commissioning of Snapper Point Power Station ahead of this summer.

The results of this sensitivity highlight that expected USE in Victoria and South Australia increases if the battery is unavailable, but does not exceed either the IRM or the reliability standard. Figure 20 shows the impact of this sensitivity in 2021-22, comparing expected USE to the base case.

Figure 20 Victorian Big Battery fire sensitivity, impacts on USE in 2021-22



4.4 Risk mitigation and summer readiness

The expected USE reported in this ESOO is an annual average representation of the risk of load shedding, using a range of statistically variable inputs. The actual occurrence of load shedding in a given year can be lower than or over the standard. Outcomes can be considerably higher than the standard with particular combinations of weather events and plant outages.

Operationally, AEMO needs to be prepared to manage the power system reliably and securely should specific events arise, such as:

- Severe weather or power system events that result in prolonged transmission network unavailability.
- Prolonged periods of generation unavailability, including forced outages and/or potential mothballing. (see below).

- Delays to the commissioning of new renewable generation or battery capacity.
- Operational impacts of extreme temperature on wind farms that may reduce generation output to 0 MW unexpectedly.
- Operating the network during periods of minimum operational demand (see Chapter 6).
- Completion of pre-summer maintenance and project work.

The risks discussed in sections 4.1 to 4.3 and above are being further considered in AEMO's collaborative summer readiness program:

- As with previous years, AEMO will collaborate with industry to identify the preparedness of the system for summer, and operational options to mitigate these risks. AEMO is working closely with generators and transmission network service providers (TNSPs) to ensure outages are co-ordinated and essential summer readiness work is completed prior to summer.
- AEMO can mitigate some of the supply adequacy risks with the use of medium notice and short notice RERT in the first instance, if required. These forms of RERT ensure consumers do not pay for additional reserves unless they are needed, and the benefits of calling on any out-of-market reserves outweigh the costs.
- In addition to supply adequacy, as assessed in this ESOO, AEMO will review operational processes, contingency planning, and communications as part of its summer readiness program.

Major unexpected disruptions may occur in the NEM, as demonstrated by the extended outage of Callide C Unit 4 after it stopped generating on 25 May 2021. If a major unexpected disruption occurred in the lead-up to summer, such as an extended outage at a generator or another key transmission asset, AEMO would reassess whether expected USE exceeded the IRM, communicate any changes through the release of an ESOO update, and may seek to secure either interim reliability reserves or medium notice RERT, if required.

5. RRO reliability forecasts

This chapter meets AEMO’s obligations under Section 4A.B.1 of the NER 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.

AEMO has prepared the reliability forecast against the IRM for this financial year and the next three financial years, and against the reliability standard for the financial year 2025-26 and for the indicative reliability forecasts (2026-27 to 2030-31 inclusive).

5.1 Key assumptions

This reliability assessment includes all existing and committed generation and storage, including retirements reported in the Generation Information page published in July 2021⁵⁷, as well as committed and relevant anticipated transmission augmentations (see Section 3).

Specifically, the assessments:

- Do not include major transmission investments that have not yet completed all necessary approvals, including HumeLink (the new transmission development to unlock congestion and enable the benefits of Snowy 2.0 to be delivered to the NEM).
- Include the diesel generators in South Australia – Temporary Generation South is assumed to remain at the existing site until plans for the new site ‘Bolivar’ develop further, and Snapper Point Power Station is included from July 2023 onwards (given its status as Committed*).
- Do not include any additional capacity that could be made available through RERT⁵⁸.

As the level of forecast USE observed in Queensland and Tasmania is negligible throughout the 10-year ESOO planning horizon, these regions have been removed from the presentation of USE outcomes in this chapter.

5.2 The reliability forecast (first five years)

Forecast expected USE remains below both the IRM of 0.0006% and the reliability standard of 0.002% in all regions in the first five years of the reliability forecast (2021-22 to 2025-26), as shown in Figure 21.

Key outcomes include:

- In South Australia, the modelled commissioning of Snapper Point Power Station (in July 2023), the reported return to service of Torrens Island B1 unit from mothballing (in October 2024), and the

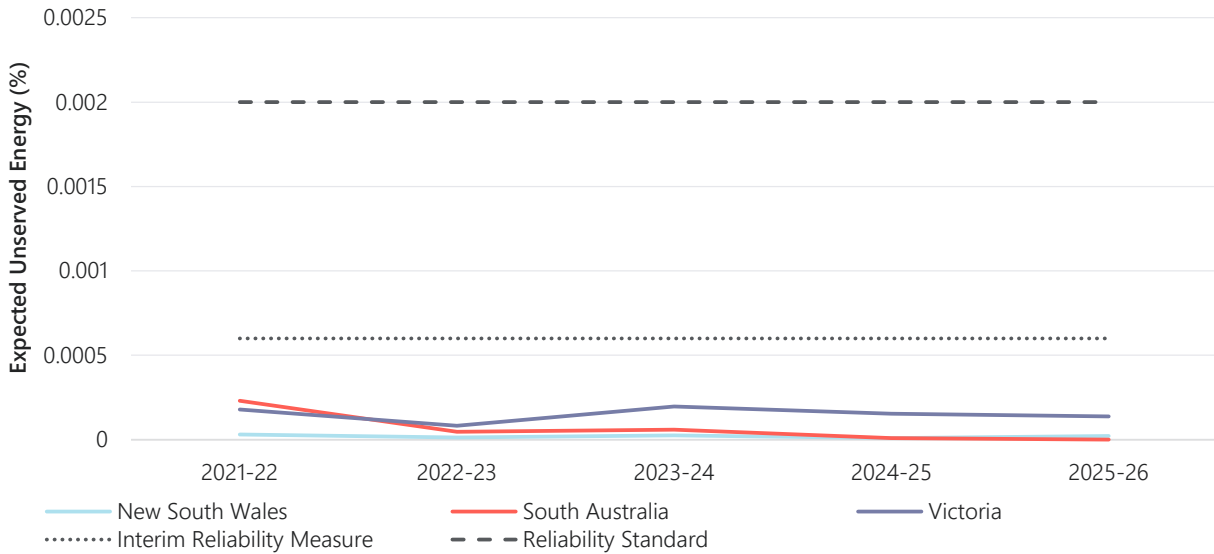
⁵⁷ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

⁵⁸ The exception being DSP responses from RERT panel members delivered outside RERT, which have been included in the DSP forecasts. See DSP methodology for more details, at <https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation>. Further information on what reserve is acceptable for RERT is available at <https://www.aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert>.

commissioning of Project EnergyConnect (from 2023-24) help maintain reliability well below the IRM once Osborne Power Station retires in 2023-24.

- In New South Wales, the commitment of new generation capacity, including the 750 MW Kurri Kurri Power Station which is expected to be operational in December 2023, has closed the forecast reliability gap that had previously been identified in 2023-24 following the retirement of Liddell Power Station.
- In Victoria, expected USE is forecast to remain below the IRM over the five-year horizon, with only minor changes year to year.

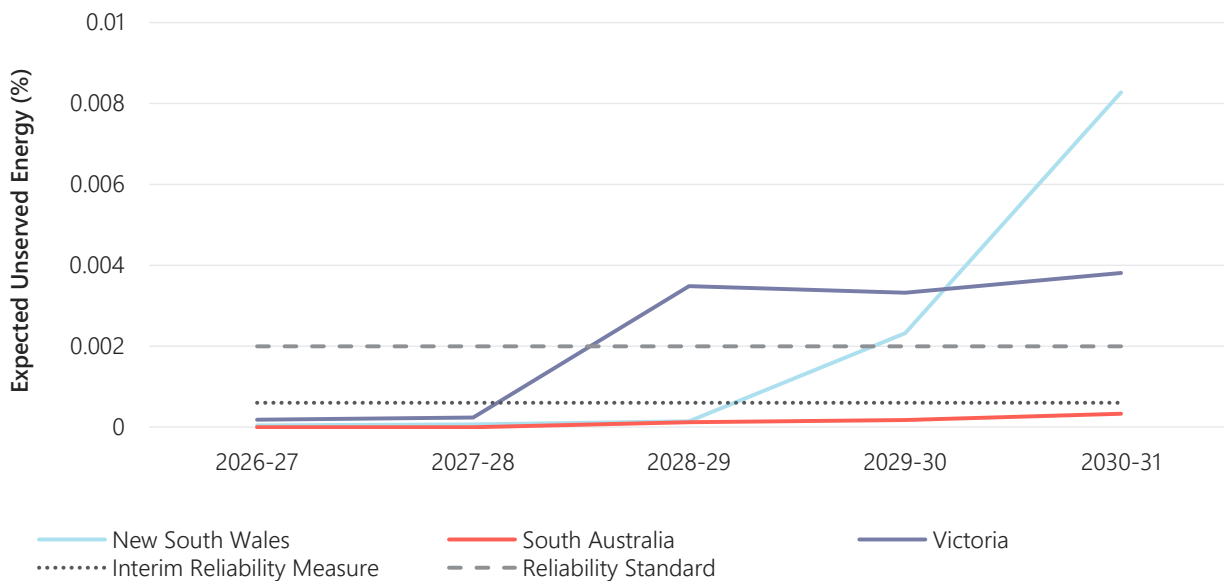
Figure 21 Reliability forecasts, first five years (2021-22 to 2025-26)



5.3 The indicative reliability forecast (second five years)

Figure 22 shows expected USE over the second five years of the 2021 ESOO (2026-27 to 2030-31).

Figure 22 The indicative reliability forecasts, second five years (2026-27 to 2030-31)



Reliability is forecast to deteriorate over this period in New South Wales and Victoria. Major drivers of this deterioration are:

- The retirement of Yallourn Power Station (1,450 MW) in Victoria in July 2028.
- The retirement of Vales Point Power Station (1,320 MW) in New South Wales in 2029-30.
- The retirement of one unit (720 MW) of Eraring Power Station in New South Wales in 2030-31.
- Expected increases in forced outage rates of coal-fired generators over time.
- Forecast increases in consumer demand towards the end of the decade.

5.4 Possible actions to improve the reliability outlook

Possible actions to improve the reliability outlook in New South Wales include:

- The HumeLink augmentation (which has not yet completed its regulatory approval process, and therefore not included in the analysis) to help unlock the reliability benefits provided by the expected commissioning of Snowy 2.0 in 2025-26.
- Reinforcement of the transmission network around Sydney, Newcastle, and Wollongong to support power transfer into the Sydney load centre in peak periods following the retirement of Vales Point Power Station and one unit at Eraring Power Station. The 2020 ISP identified preparatory activities on a future project for this purpose⁵⁹, as the existing network limitations restrict the ability to transfer power from regions beyond the Hunter Valley into the Sydney load centre.
- Continued generation and storage investment, including the anticipated development of Tallawarra B and investment facilitated through the New South Wales Electricity Infrastructure Roadmap.
- Implementation of the New South Wales peak demand reduction scheme, and increases in WDR and DSP.

Possible actions to improve the reliability outlook in Victoria include:

- Continued generation and storage investment and development of additional DSP resources. This includes the 350 MW, four-hour, large-scale Jeeralang Battery being developed by 2026 as part of Energy Australia's agreement with the Victorian Government to deliver an orderly retirement of Yallourn Power Station⁶⁰. While this project does not yet meet AEMO's commitment criteria, the project is underway and, once built, would close much of the forecast reliability gap in Victoria towards the end of the decade.
- The VNI West augmentation (which has not yet completed its regulatory approval process and therefore not included in the analysis), to increase New South Wales to Victoria transfer limits, and support the development of additional renewable energy zones (REZs) in north-west Victoria and south-western New South Wales.
- Development of MarinusLink to increase transfer capacity between Tasmania and Victoria.

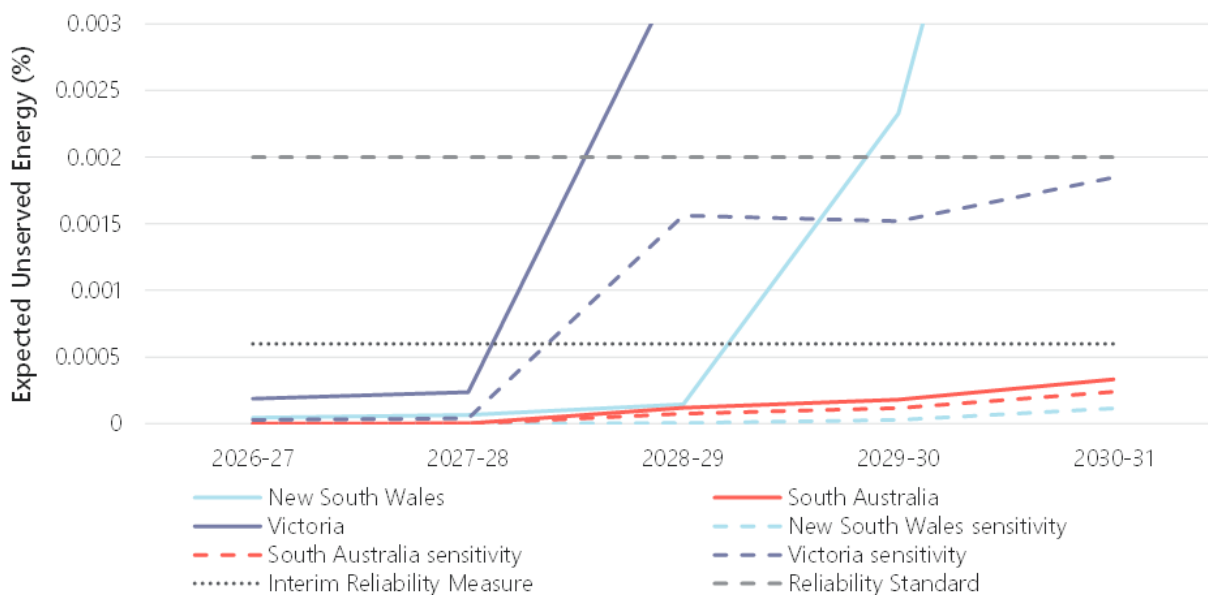
Figure 23 shows expected USE over the second five years of the 2021 ESOO (2026-27 to 2030-31) assuming the anticipated development of Tallawarra B occurs, the Jeeralang Battery in Victoria and Torrens Island Battery in South Australia are developed, and HumeLink and Sydney Reinforcement transmission projects proceed to enable the reliability benefits of Snowy 2.0 to be fully realised.

It highlights that these projects in combination would be sufficient to bring expected USE down below the reliability standard throughout the next decade in both Victoria and New South Wales.

⁵⁹ See <https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en>.

⁶⁰ See <https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition>.

Figure 23 Reliability impact of projects well advanced, but not yet meeting AEMO’s commitment criteria, second five years (2026-27 to 2030-31)



5.5 Reliability forecast components

5.5.1 Identification of forecast reliability gaps

Under 14G(1) of the National Electricity Law, a forecast reliability gap occurs when the amount of electricity forecast for a region, in accordance with the NER, does not meet the reliability standard (0.002% USE in a financial year) to an extent that, in accordance with the NER, is material.

Under NER clause 4A.A.2, a gap is defined to be material if it exceeds the reliability standard.

In November 2020, the NER were amended by the National Electricity Amendment (Retailer Reliability Obligation trigger) Rule 2020, which temporarily changed AEMO’s reporting obligations for reliability forecasts. The rule change requires AEMO to report on whether the IRM (0.0006% USE in a financial year) would be exceeded in financial years up until 30 June 2025, after which the reporting obligation reverts to the previous position under the NER; that AEMO must report on whether the reliability standard would be exceeded in any financial year.

For this 2021 ESOO, AEMO’s reliability forecasts therefore report against the IRM for this financial year and the next three financial years and against the reliability standard for the financial year 2025-26 and for the indicative reliability forecasts (2026-27 to 2030-31 inclusive).

A forecast reliability gap will exist if expected USE:

- Exceeds 0.0006% of the total energy demanded in that region for a given financial year between 2021-22 and 2024-25.
- Exceeds 0.002% of the total energy demanded in that region for a given financial year between 2025-26 and 2030-31.

This section outlines any forecast reliability gaps, and where relevant, the associated reliability forecast components.

Forecast reliability gaps

Forecast reliability gap in the reliability forecast

In the 2021 ESOO, no forecast reliability gaps have been identified in any region in the five-year reliability forecast.

Indicative forecast reliability gaps

In the indicative reliability forecast (second five years), forecast reliability gaps occur in New South Wales in 2029-30 and 2030-31, and in Victoria in 2028-29 to 2030-31, as expected USE exceeds the reliability standard of 0.002% for these regions in these financial years. The reliability forecast components associated with these forecast reliability gaps are summarised below.

Forecast reliability gap in the *indicative* reliability forecast (based on 0.002% reliability standard)

For New South Wales in 2029-30:

- The forecast reliability gap period is from 1 January 2030 to 28 February 2030.
- The expected USE for the forecast reliability gap period is 1.14 gigawatt hours (GWh).
- The size of the forecast reliability gap is 120 MW.

For New South Wales in 2030-31:

- The three forecast reliability gap periods are from 1 July 2030 to 31 July 2030, from 25 November 2030 to 28 February 2031, and from 1 June 2031 to 30 June 2031.
- The expected USE for the above forecast reliability gap period is 0.23 GWh, 4.29 GWh and 0.56 GWh respectively.
- The size of the forecast reliability gap is 970 MW.

For Victoria in 2028-29:

- The forecast reliability gap period is from 1 January 2029 to 28 February 2029.
- The expected USE for the forecast reliability gap period is 1.17 GWh.
- The size of the forecast reliability gap is 275 MW.

For Victoria in 2029-30:

- The forecast reliability gap period is from 1 January 2030 to 28 February 2030.
- The expected USE for the forecast reliability gap period is 1.09 GWh.
- The size of the forecast reliability gap is 270 MW.

For Victoria in 2030-31:

- The forecast reliability gap period is from 1 January 2031 to 28 February 2031.
- The expected USE for the forecast reliability gap period is 1.27 GWh.
- The size of the forecast reliability gap is 390 MW.

5.5.2 One-in-two year peak demand forecast

In accordance with NER clause 4A.A.3, AEMO must specify the forecast one-in-two year peak demand in the reliability forecast. As agreed through consultation with industry, AEMO reports the 50% POE operational maximum demand forecast on an 'as generated' basis for this purpose.

The performance of these demand forecasts is included in AEMO's *Forecast Accuracy Report*⁶¹.

Table 5 AEMO's one-in-two year peak demand forecast (50% POE, as generated)

Financial Year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2021-22	13,111	9,697	2,928	1,739	9,095
2022-23	12,985	9,762	2,921	1,768	9,035
2023-24	12,856	9,752	2,911	1,780	9,034
2024-25	12,864	9,865	2,905	1,796	9,024
2025-26	12,998	9,950	2,909	1,802	8,972

The only difference between Table 5 and the operational maximum demand values reported by region in Appendices A1-A5 on a 'sent out' basis is the inclusion of auxiliary load forecasts at time of maximum demand⁶².

The forecast auxiliary load amounts at the time of maximum demand for 50% POE demand conditions are shown below in Table 6. These values have been determined based on modelling outcomes which model the auxiliary rates of each generating unit based on information provided by participants.

Average auxiliary load rates at the time of one-in-two year peak demand are forecast to remain relatively static over the next five years in all regions. Coal-fired generation typically has higher auxiliary loads than other generation types. Auxiliary loads therefore reduce as coal-fired generators retire, as observed in New South Wales when Liddell retires.

Table 6 Auxiliary usage (in MW) forecast at time of one-in-two year peak demand (50% POE)

Financial Year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2021-22	423	492	42	20	372
2022-23	417	509	41	19	371
2023-24	398	509	39	18	373
2024-25	401	514	43	19	368
2025-26	403	514	38	19	364

Forecasting auxiliary loads much beyond the next five years is challenging, as it will depend on what new resources are developed, and where, in response to generator retirements and changes in demand.

⁶¹ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting>.

⁶² See AEMO's *Electricity Demand Forecasting Information Paper*, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

5.6 Additional information on the reliability forecast

For completeness, and separate to the reporting requirements in relation to the RRO, AEMO reports any forecast reliability gaps to meet the reliability standard and the IRM in Table 7 below.

Table 7 Forecast reliability gap (in MW) to meet the reliability standard (of 0.002%) and the IRM (of 0.0006%)

	Gap to meet reliability standard of 0.002%			Gap to meet reliability standard of 0.0006% (IRM)		
	Victoria	South Australia	New South Wales	Victoria	South Australia	New South Wales
2021-22	0	0	0	0	0	0
2022-23	0	0	0	0	0	0
2023-24	0	0	0	0	0	0
2024-25	0	0	0	0	0	0
2025-26	0	0	0	0	0	0
2026-27	0	0	0	0	0	0
2027-28	0	0	0	0	0	0
2028-29	275*	0	0	1,120*	0	0
2029-30	270*	0	120*	1,235*	0	1,645*
2030-31	390**	0	970**	2,035**	0	2,030**

*Calculated using a loss of load probability (LOLP) threshold of 8%, because the gap could not be calculated using a 10% LOLP threshold.

** Calculated using a LOLP threshold of 6%, because the gap could not be calculated using a 10% or 8% LOLP threshold.

For more information, see the *ESOO and Reliability Forecast Methodology* on the selection of LOLP thresholds (last updated August 2021).

6. Factors and implications of an accelerated transition

Multiple interrelated drivers are accelerating the energy transition in the NEM and making the management of system reliability and security more complex:

- Unprecedented levels of underlying demand supplied by DER (see Section 6.1).
- Accelerated exit of coal-fired generation and decreasing plant reliability (Section 6.2).
- Accelerated changes towards hydrogen production and consumers switching from other fuels to electricity (Section 6.3).

6.1 Challenges and opportunities during high DER penetration periods

The NEM is pioneering world-first operation of a major power system with unprecedented levels of underlying demand supplied by DER. To manage this operating condition, a number of adaptations are required for the power system to continue operating securely, reliably, safely and affordably.

If these actions are not taken, AEMO estimates that it will no longer be possible to operate the mainland NEM securely in some periods from 2025 with the current operational toolkit; this could be earlier under abnormal network conditions such as line outages.

Adaptations are required across a number of categories, including improving foundational power system security capabilities, developing suitable regulatory and market frameworks, building social licence, and creating opportunities for new services delivered by market participants.

Delivering these enhancements and building that social licence will enable consumers to access new markets and harness the full value of their DER.

Based on current trends, AEMO expects that, at certain times of the day, with the power system engineered appropriately, there could be up to 100% instantaneous penetration of renewables in at least some dispatch intervals throughout the year by 2025 (see Section 3.2). While this ESOO focuses on operating the NEM power system at times of high DER and low operational demand, it is important to note that distributed PV is only a subset of renewable generation in the NEM, which also includes other IBR (large-scale wind and solar generation). The work required to support operating a high DER power system is closely linked to the broader need to operate a power system with 100% of underlying demand supplied by renewable generation⁶³, or even supplied solely by IBR, in some periods within the next decade⁶⁴.

⁶³ Includes grid-scale wind and solar, hydro, biomass and distributed PV.

⁶⁴ AEMO is collaborating with industry on the broader implications of operating the power system with high IBR, and on implementation workplans; see <https://www.aemo.com.au/initiatives/major-programs/engineering-framework>.

6.1.1 Pioneering world-first operation with high DER

The NEM is leading the world in growth of distributed PV⁶⁵. The mainland NEM⁶⁶ experienced a daytime minimum operational demand record of 15 GW on 29 September 2019. On 10 October 2020, a record maximum of 35% of underlying demand in the mainland NEM was met by distributed PV, and operational demand reached a new minimum record of 13.6 GW. AEMO projects that by 2026, distributed PV could at times supply up to 77% of underlying demand⁶⁷ in the mainland NEM.

Some parts of the NEM have times when even higher levels of demand are met by DER. South Australia has achieved periods with up to 78% of underlying demand met by distributed PV and is, to AEMO's knowledge, the first gigawatt-scale power system in the world to approach periods with 100% of underlying demand being supplied by DER. Under some scenarios, periods with 100% of underlying demand in South Australia being supplied by distributed PV could occur as early as spring this year. Distributed PV has also supplied up to 42% of underlying demand at times in Victoria, 38% in Queensland, and 32% in New South Wales⁶⁸.

While these developments challenge the limits of the current power system, they also provide the opportunity for pioneering market frameworks that provide new consumer benefits and demonstrate world-first power system operation.

The transition to a power system supplied primarily by DER in some periods represents an unprecedented change in power system and electricity market operation. Growth in installed distributed PV is forecast to remain high driven by consumers seeking to better manage their energy use, security, and costs⁶⁹, as well as the influence of non-financial factors such as changes in consumer awareness and solar industry competitiveness and marketing⁷⁰.

AEMO currently manages the dispatch of centralised generation⁷¹ to maintain the power system within a secure technical envelope. The dispatch of these centralised generators is actively managed minute by minute to maintain precise supply-demand balance in every dispatch interval. In doing this, AEMO needs to ensure the network is operating within technical limits, voltages are maintained within the required ranges, and there is sufficient frequency control headroom and footroom across the fleet to manage contingency events and second-by-second supply-demand variation.

However, a power system supplied primarily by DER operates very differently. Most distributed PV systems in the NEM today operate in a passive manner – they are not subject to the same performance requirements as centralised generation and are not visible or controllable by distribution network service providers (DNSPs), even under emergency conditions⁷².

Therefore, if nothing changes, and a smaller and smaller proportion of the generating fleet is able to be actively managed, AEMO will need to try to maintain the power system within a secure technical envelope with progressively decreasing operational flexibility. Beyond a certain point, it is no longer possible to operate the power system securely.

Fortunately, new technology now available makes it entirely feasible for DER to be actively managed.

⁶⁵ Distributed PV includes rooftop systems and other smaller non-scheduled PV capacity.

⁶⁶ The mainland NEM refers to the combined network of Queensland, New South Wales, Victoria and South Australia.

⁶⁷ 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 PV and battery storage – see Section 1.2.

⁶⁸ Victoria and South Australia historical minimum demand records are noted in AEMO's Quarterly Energy Dynamics Q4 2020, p.8, at <https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q4-2020.pdf?la=en>.

⁶⁹ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/nem-electricity-demand-forecasts/2017-electricity-forecasting-insights/key-component-consumption-forecasts/rooftop-pv-and-battery-storage>.

⁷⁰ See p. 11, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf.

⁷¹ Meaning scheduled and semi-scheduled generation.

⁷² Only one DNSP in the NEM has this capability. For more, see AEMO's Renewable Integration Study (RIS) Stage 1 report, p. 38, at <https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris>.

Virtual power plants (VPPs)⁷³ are emerging across the NEM, and South Australia has pioneered active management capabilities⁷⁴ for all new distributed installations⁷⁵. If introduced and leveraged effectively, this capability provides the opportunity for consumers to make further savings from their DER, as well as pioneering a new way of operating a secure, safe, reliable and affordable power system, supplied primarily by distributed resources.

6.1.2 Emerging challenges

AEMO has identified a range of technical areas where challenges are arising and adaptations are required to facilitate the transition to a power system that can operate securely and reliably with high levels of distributed PV. These areas include:

- **Ensuring sufficient operational demand for delivery of essential system security services** – operational demand must always be high enough to support the minimum generation levels for units providing essential security services. This is discussed in more detail in Section 6.1.3 below.
- **Managing and minimising the unintended disconnection of distributed PV** during faults and other kinds of power system disturbances – the disconnection of distributed PV following disturbances increases contingency sizes, which increases the need for frequency control services, and adversely affects network stability limits. AEMO has worked extensively with stakeholders to update Australian Standard AS/NZS 4777.2 to minimise unintended disconnections from future DER installations⁷⁶. Updates to frequency control arrangements and other power system limits are also required to manage legacy fleet disconnection behaviour⁷⁷.
- **Maintaining transmission voltages** in the necessary ranges when the operational demand is low (the network is lightly loaded).
- **Maintaining a sufficient emergency under-frequency response** to manage severe non-credible disturbances – distributed PV is reducing the net load on under frequency load shedding (UFLS) circuits, reducing its effectiveness in arresting a frequency decline. This capability needs to be restored, as UFLS is an important safety net that is the last line of defence protecting consumers from black system events.
- **Maintaining the ability to perform a system restart** under conditions of very low operational demand – at present, system restart requires the start-up of transmission-connected synchronous generators. These generating units require a minimum level of stable load to operate above their minimum loading levels. In high DER periods, there may not be enough stable load available in the vicinity.

6.1.3 Minimum level of operational demand for delivery of essential system security services

At present, the power system relies on the dispatchability of centralised units (including large-scale wind, solar, coal, gas and hydro units) to maintain supply-demand balance in all periods. A minimum number of centralised units must be maintained online, at or above minimum generation levels, to supply essential system security services⁷⁸, including system strength, inertia, frequency control, voltage control and reactive power management, and ramping management. Some of these services, such as inertia and system strength,

⁷³ VPP refers to an aggregation of resources (such as decentralised generation, storage and controllable loads) coordinated to deliver services for power system operations and electricity markets.

⁷⁴ Active management capabilities refers to the ability to remotely adjust the behaviour of a distributed resource.

⁷⁵ Government of South Australia, Department of Energy and Mining, Remote Disconnect and Reconnection of electricity generating plants, at https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes/remote_disconnect_and_reconnection_of_electricity_generating_plants.

⁷⁶ AEMO (April 2019) *Technical Integration of Distributed Energy Resources*, at <https://aemo.com.au/-/media/files/electricity/nem/der/2019/operations/technical-integration-of-der-report.pdf?la=en&hash=65EAE8BA3C64216F760B16535CE2D3ED>.

⁷⁷ AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, at <https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf>.

⁷⁸ AEMO (July 2020) *Power System Requirements*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

can only be effectively provided by centralised synchronous units (such as coal, gas and hydro units, or synchronous condensers) at this time.

To support the minimum generation levels of units providing the required essential services, with the present operational toolkit, AEMO estimates that a minimum of approximately 4-6 GW of operational demand is required in the mainland NEM.

This estimate is based on the physical assets currently available in the NEM, and assumes all non-essential centralised generation – any centralised generator that is not delivering an essential system security service – will be curtailed, by normal market operation and likely negative prices, at times of minimum demand⁷⁹. It also assumes the NEM mainland is exporting at maximum levels to Tasmania (via the Basslink interconnector)⁸⁰, hydro pumping loads are operating at these times⁸¹, and all mainland NEM regions are interconnected, without network limits. This is not the case in many periods. If there are network limits, Basslink is unavailable⁸², or hydro pumping loads are unavailable, the amount of minimum operational demand required will be higher, which will mean that critical thresholds are reached sooner.

Investment in new assets that can provide the necessary levels of these essential system security services with lower minimum loading levels could reduce this threshold below 4-6 GW. This could include, for example, commissioning of synchronous condensers⁸³ to deliver system strength and inertia, reactors to deliver voltage control and batteries and other resources to deliver frequency control. AEMO is currently undertaking its 2021 assessments of Network Support and Control Ancillary Services (NSCAS), system strength and inertia. These assessments will consider whether any shortfalls will be declared under the regulatory framework, to be addressed by investment or service delivery from the transmission network service providers.

The NEM is designed for an efficient level of investment in regulated services (including system security services) at any point in time, with the long-term interests of consumers in mind. As such, the planning frameworks are specifically designed not to address every possible operational condition or need at any cost, and instead are based on economic-engineering trade-offs of needs and risk-cost-benefits, with operational measures addressing certain abnormal operating conditions, as occurs with the Lack of Reserve (LOR) and UFLS framework.

This means that, even if they are used rarely, AEMO still needs robust operational measures in its suite of last resort actions to deal with more extreme outcomes and avoid major disruption, damage to infrastructure, or safety risks.

Estimate of when critical operational demand thresholds will be reached

AEMO's forecasts indicate that NEM mainland demand could be in the range of 4-6 GW by 2025 in the Central scenario, or as early as 2024 in some scenarios.

⁷⁹ This analysis incorporates a 'return-to-secure' buffer. This buffer ensures that in the event that the largest load trips and does not return within 30 minutes, that there will be sufficient post-contingency lower FCAS services to operate a secure system. The 'return-to-secure' buffer is equal to the size of the largest post-contingency load. This analysis assumes full FCAS from large-scale battery energy storage systems availability and adds 160 MW to the thresholds meet lower regulation FCAS requirements.

⁸⁰ It assumes there is the potential to export up to 400 MW of generation to Tasmania via Basslink. During times of low load in the mainland NEM (less than 14,000 MW operational demand), Basslink has a typical export limit 400 MW into Tasmania.

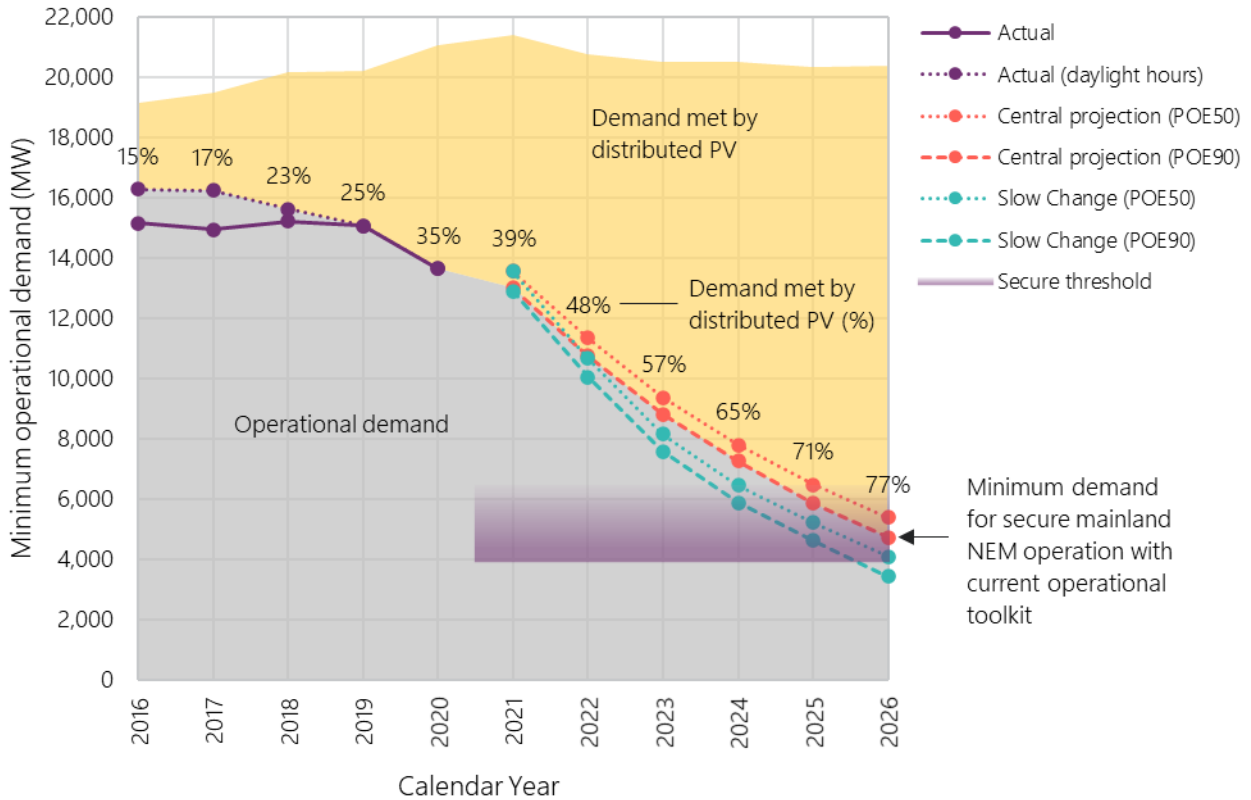
⁸¹ Total pumping load for the mainland NEM is assumed to be 540 MW.

⁸² The Basslink interconnector can have extended outages, meaning that the NEM mainland may need to operate without a connection to Tasmania in some periods. In 2019, the Basslink Interconnector was unavailable for more than one month due to equipment failure, while in 2018, damage during maintenance left it unavailable for more than two months. This followed the outage of almost six months beginning in 2015 due to a fault on the subsea cable.

⁸³ The four synchronous condensers commissioned by ElectraNet to deliver system strength and inertia in South Australia are already included in this assessment. This statement refers to additional investment in synchronous condensers.

Figure 24 shows historical and forecast minimum operational demand⁸⁴ levels for the mainland NEM (excluding Tasmania).

Figure 24 Minimum operational demand in the NEM mainland (excluding Tasmania)



Actual minimum demand values are determined for each calendar year, whereas forecast values are on a 'season-year' basis. A 'season-year' extends from 1 September to 31 August. Coincident mainland NEM minimum demand forecasts were determined by summing regional non-coincident minimum demand forecasts and applying a historical scaling factor. Minimum demand can occur at different times in each region - the historical scaling factor was used to account for this.

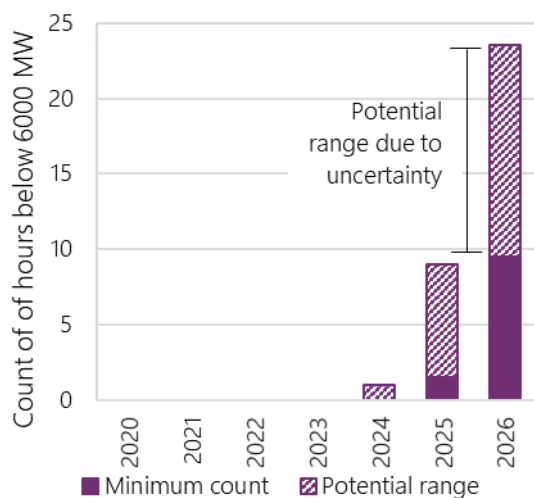
Figure 25 shows the forecast incidence of operational demand falling below the 6 GW threshold in multiple simulations, and an example of the demand profile on the minimum operational demand day.

Initially, the occurrence of demand below this threshold is very rare, and only applies to a small handful of intervals. Over time, the incidence and duration of periods below these thresholds will grow.

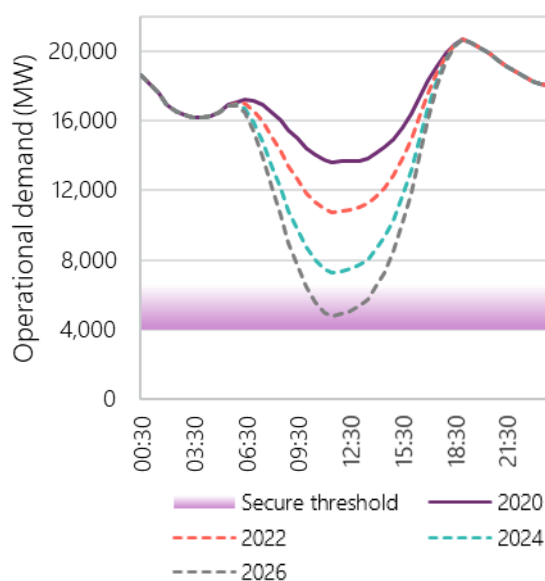
⁸⁴ Minimum demand thresholds, actuals, and forecasts in this chapter are presented on an 'as generated' basis, and include generator auxiliary loads. For more information on demand definitions, see Section 1.2.

Figure 25 Forecast incidence and duration of operational demand below secure thresholds (NEM mainland)

(a) Indicative range of operational demand below 6,000 MW across central scenario



(b) Example minimum demand day, Central projection 90% POE



Multiple simulations with varying POE were run to determine the number of hours in which demand fell below 6,000 MW. This represents a wider spread of possibilities than used in Figure 24.

Operationally challenging periods will arise in some periods before operational demand reaches the 4-6 GW threshold, particularly during management of abnormal circumstances such as network and unit outages, possibly associated with bushfires, storm events, explosions and other extreme events. These sorts of challenges are expected to drive the earliest need to implement measures to maintain a secure power system under low operational demand conditions. It is difficult to predict how often these sorts of abnormal circumstances may arise, since they are often caused by rare and unusual natural events.

Operationally challenging periods are also likely to emerge earlier than these timelines in some regions, particularly under conditions with network outages or when operating sub-regions of the power system as islands, as summarised in Table 8. Further details are provided in Appendices A2, A3, and A5.

Table 8 Minimum operational demand thresholds in specific regions (with present operational toolkit)

Region	System condition	Minimum operational demand thresholds	Forecast date when thresholds are reached
South Australia	Secure operation of an island	600 MW	Minimum operational demand levels below these thresholds have already occurred.
	Credible risk of separation	400 MW	Minimum operational demand levels below these thresholds have already occurred.
Victoria	System normal threshold for system strength units	0.8 – 1.6 GW	2023
	Secure operation of Victoria + South Australia island	1.8 – 3.5 GW	2021 or 2022
Queensland	Secure operation of an island	2.5 – 3.4 GW	2021 or 2022
	System normal threshold for system strength units (with Wivenhoe pumping load)	1.2 – 1.7 GW	2025 or 2026

Additional operational demand in the middle of the day that can act as a 'solar soak' would help reduce the incidence of security challenges and minimise the need for operational intervention. For example:

- Introduction of effective market-based mechanisms that recognise and reward the value of consumer flexibility could help shift more load to low demand periods.
- Beyond the horizon of the analysis above, the significant storage of Snowy 2.0 is planned for commissioning from 2025-26, with a nameplate capacity of 2,040 MW and storage capacity of 350 GWh. When operating in pumping mode, the operation of Snowy 2.0 could reduce these thresholds, however the forecast rate of decline in minimum demand will mean this is not sufficient in isolation to address these challenges long term.
- Also beyond the horizon of this analysis, and highly uncertain, flexible hydrogen electrolyser load, EV charging, and increased electrification all have the potential to raise operational minimum demand (see Section 6.3).

Implications if no action is taken

As operational demand in the mainland NEM starts to fall into the range of 4-6 GW, there will be reduced operational flexibility and it will become increasingly challenging to operate the NEM mainland with all the required security services.

If operational demand falls below this range, it will become increasingly necessary to take extreme actions. This could include selectively shedding (disconnecting) whole distribution feeders if they are operating in reverse flows (that is, acting as a net generator, supplying power back into the grid). Disconnecting the feeder at these times therefore acts to increase the operational load. However, disconnecting the feeder also means that all consumers on the feeder lose power supply. If other options are not made available, this may be the only remaining option to increase operational load and maintain a core power system that can support the operation of generating units delivering essential security services. With the capabilities currently available to network operators, this would mean consumers on feeders with high levels of distributed PV installed would not have power supply, potentially for extended periods during daylight hours (as illustrated in Figure 25), and potentially on repeated days during shoulder seasons (spring and autumn, when periods of minimum demand are often observed). It may be necessary to shed a large proportion of consumer load to recover a relatively small amount of net demand, since reverse flows are often distributed across many locations in the network.

In some regions with minimal large industrial load (where the majority of consumer load is residential and associated with high uptake of small-scale distributed PV), at some point it may no longer be possible to recover enough load by shedding consumer feeders. When this approach is exhausted, it would no longer be possible to operate the NEM mainland securely in low operational demand periods. This means the power system would not have adequate frequency control and system strength to avoid possible automatic UFLS or generator tripping in the event of a credible contingency.

Given the compounding impacts of distributed PV to reduce the robustness of backup safety-net mechanisms such as UFLS, it is possible that in some circumstances a moderate contingency (such as a generator trip or network fault) could result in a cascading failure to a black system. Contingency events are common:

- Incidents such as loss of transmission elements, loss of generation, and load interruption were reported at a rate of at least once a week across the NEM during the period from 2018 to 2021⁸⁵.
- In 2020, 153 credible load and generation events activated contingency FCAS⁸⁶.

⁸⁵ This estimate includes incidents related to market operations, real-time operation, system performance and/or commercial, and documented on AEMO's Systems Market Incident Reporting Kiosk (SMIRK). It excludes incidents primarily caused by procedural issues, operational errors, and non-conformance.

⁸⁶ AEMO (February 2021) Appendix A, *Frequency and Time Error Monitoring – Q4 2020*, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/quarterly-reports/2020/frequency-and-time-error-monitoring-4th-quarter-2020.pdf?la=en.

- Incidents that were severe enough for AEMO to deem them reviewable occurred at a rate of approximately one per fortnight across the NEM in 2020⁸⁷.

The high rate of occurrence of contingency events means that operating for longer than thirty minutes without the required frequency control and system strength services puts the NEM at high risk. If adaptations are not implemented, it is foreseeable that there could be extended periods for many hours during the middle of the day and over repeated consecutive days where the NEM or parts of the NEM may not be secure.

This puts consumers at elevated risk of black system events. Each black system event is estimated to have costs to consumers in the range of \$300-\$500 million⁸⁸. The black system event that occurred in South Australia on 28 September 2016 was estimated to cost commercial consumers alone approximately \$367 million (based on consumer surveys)⁸⁹.

6.1.4 Adaptations to manage reducing minimum operational demand

No single institution, industry sector or consumer group can address all of the technical challenges noted in Section 6.1.2. A range of adaptations will be required to ensure the power system continues to operate securely, reliably, safely and affordably with high levels of DER and this will require the collaboration of AEMO, market bodies, governments, industry, and consumer advocates.

These adaptations fall into four categories:

- **Social licence for DER active management** – one of the key foundational security adaptations is the active management of consumers’ systems, and AEMO is committed to partnering with consumer representatives in building social licence to enable this capability.
- **Adapted market and regulatory frameworks** – these are needed to fully unlock emerging opportunities for stakeholders and bring the new services required to the market. This includes frameworks for active DER and load participation in markets, dynamic operating envelopes, Distribution System Operator (DSO)⁹⁰ frameworks and improved frameworks for harnessing the many value streams available from storage, and improved frameworks for valuing new services. With the majority of resources in a high DER system being owned and operated by consumers, it is essential that suitable market and regulatory frameworks are in place to allow consumers the opportunity to fully participate, and to align behaviour incentives with power system needs, thereby reducing the use of emergency operational mechanisms. Frameworks designed to help consumers and stakeholders make efficient decisions and be rewarded appropriately when their actions deliver benefits to others are currently being developed under the Energy Security Board’s (ESB’s) Post 2025 market design program.
- **Foundational security adaptations** to power system operation, to support ongoing power system security – AEMO is undertaking a collaborative suite of work activities with stakeholders to ensure the models, tools, control schemes, operating procedures, and other measures (such as basic emergency backstop curtailment of distributed PV) are in place to provide a robust and resilient foundation of a secure power system, in which opportunities for consumers and stakeholders can be fully realised.
- **Emerging opportunities for stakeholders** – given the scale of this transition, and the breadth of new resources emerging in the market, a suite of new opportunities for consumers and industry stakeholders are expected to arise. While many opportunities are nascent at present, and market frameworks that

⁸⁷ AEMO, Power system operating incident reports, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports>.

⁸⁸ AEMO (November 2018) AEMO Request for Protected Event Declaration, at <https://www.aemc.gov.au/sites/default/files/2019-04/AEMO%20Request%20for%20protected%20event%20declaration.pdf>.

⁸⁹ AEMC (12 December 2019) South Australian black system review, at https://www.aemc.gov.au/sites/default/files/documents/aemc_-_sa_black_system_review_-_final_report.pdf.

⁹⁰ Distribution System Operator (DSO) refers to the entity that is responsible for planning and operational functions associated with coordinating DER services for distribution networks and/or DER participation in wholesale markets in coordination with the transmission system operator, aggregators, and other relevant parties.

provide financial incentives are still being developed and implemented, AEMO seeks to give stakeholders an early view of where and when new technical services are likely to be required, based on the best available current information, to provide transparency and facilitate efficient market development in this time of rapid change.

Further elaboration on specific adaptations required in each category is provided below, as they relate to managing minimum operational demand conditions.

Social licence for DER active management

As noted in Section 6.1.1, with more than 13 GW of rooftop solar PV operating across the NEM (representing approximately 25% of households), social licence must be built with consumers who are at the centre of this transition, and who use their DER assets to cool and heat their home, charge their EVs, or reduce their energy bills.

Historically, AEMO has managed a power system supplied primarily by centralised generators. As distributed PV becomes an increasingly important part of the energy supply chain, it is important that AEMO increases its understanding of consumers. By engaging effectively and continually building their understanding of consumers, AEMO, NSPs, Energy Networks Australia (ENA) and other stakeholders will be better placed to incorporate their preferences into solutions. Effective communication with consumers will also improve transparency and build shared understanding with consumers on the benefits to them and the broader system of proposed solutions.

A collaborative effort will be required to build social licence with consumers on how DER can be integrated into networks and the broader electricity system and market, involving a wide range of stakeholders. AEMO is also actively embedding social licence considerations into its organisation and work, including through collaboration with Energy Consumers Australia.

AEMO is approaching all of the power system and market reforms required with consumers front of mind, with design aiming to enable extended benefits for consumers.

Adapted market and regulatory frameworks

As shown in Figure 24, if the vast majority of DER remains passive, by 2026 in some periods only 23% of the generation in the NEM mainland power system will be reacting to the incentives provided via five-minute spot pricing signals. This means a large proportion of the power system may not be making energy production or consumption decisions that are aligned with power system needs. Increasing demand-side participation could help maintain sufficient power system responsiveness to incentives and pricing signals.

This highlights a need for suitable market and regulatory frameworks to effectively identify and align consumer incentives with power system needs. This work is underway within the ESB's Post 2025 DER Implementation Plan, and through Australian Energy Market Commission (AEMC) processes such as the recent rule change determination on access, pricing and incentive arrangements for DER⁹¹. For retailers and aggregators under the ESB's proposed Flexible Trader models⁹², there are opportunities, even imperatives, to develop innovative product offerings that can harness price signals that pass through without complexity to the consumer. These are already emerging, but there remains significant scope to identify and unlock new ways for consumers to benefit from smart technologies that are now technically feasible, but not yet fully supported by NEM market and regulatory frameworks. Successful implementation will be based on new models of consumer engagement.

These outcomes must be delivered quickly. In the short term (next two years), operationally challenging periods will arise during abnormal circumstances, such as network and unit outages, operation of sections of

⁹¹ AEMC (12 August 2021) Access, pricing and incentive arrangements for distributed energy resources, at <https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources>.

⁹² Energy Security Board (30 April 2021) Post 2025 Market Design Options – A Paper for Consultation – Part B, at <https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf>.

the grid while islanded, and during events such as bushfires, storms, explosions, and equipment damage. If the ESB's reforms are not successfully implemented in this timeframe, and in the absence of new daytime loads emerging, intervention will become increasingly necessary, potentially during system normal management as distributed PV levels start to exceed secure limits on a regular basis.

The necessary reforms are complex and multifaceted, and need to be commenced and implemented quickly. Full market integration of DER requires reform of complex pricing and incentive structures, as well as the physical mechanisms, communications infrastructure, and roles and responsibilities for connecting millions of distributed consumer assets into wholesale bidding processes and NEMDE dispatch algorithms, and taking into account a plethora of highly location-dependent transmission constraints and distribution network limits.

Delivering these reforms is only possible if all stakeholders work together with a common goal of achieving a safe, secure, reliable and affordable power system that can support ongoing growth in DER. It will also require innovation and leadership by different parties on different elements, including:

- The ESB exploring effective inclusion of aggregators in the wholesale market.
- AEMO and NSPs exploring approaches for facilitating DSO frameworks and dynamic operating envelopes.
- NSPs and the AEMC examining network tariff and pricing structures (building on the work in the recent rule change determination)⁹³.
- Governments examining solar feed-in tariff arrangements.
- Aggregators and retailers exploring innovative offerings with consumers.

These reforms should provide the foundation to deliver a wide array of opportunities for consumers. For example, implementation of dynamic operating envelopes may mean that the 5 kilowatts (kW) export limits applied by most DNSPs can be increased, enabling distributed PV to increase or decrease output within networks' secure operating limits. This means generation from distributed PV could be slightly curtailed to stay within operational limits during periods of peak export in the middle of the day, but allow more generation during the shoulder periods when aggregated output is lower and operational demand is higher. Similarly, it should also enable installation of more distributed PV, with less network expansion cost which would represent a cost saving for all consumers, even those without rooftop PV. Consumers will be able to take advantage of these capabilities to engage in new markets for the provision of system security capabilities as these become available, maximising the value of their system and increasing their return on investment.

Foundational security adaptations

The reforms described above are complex. As these reforms are developed, the risks highlighted in Section 6.1.2 and 6.1.3 can be mitigated, and distributed PV growth supported to flourish, if a Contingency and Minimum System Load (CMSL) Framework is introduced in all NEM regions. Designed to address the operational challenges outlined in Section 6.1.2, a CMSL Framework will outline a tiered market and operational response with a series of escalating measures to maintain system security, similar to that in the LOR framework. Tiers include the application of dynamic operating envelopes (when available) and market notices to signal for flexible generation and load based responses, operational interventions such as the recall of line outages, and finally a last resort measure via an emergency PV curtailment backstop, to be utilised if the previous tiers have not maintained system security. To enable the backstop capability, it is necessary to introduce a requirement for new distributed PV installations to have the capability to be curtailed when required as a last resort to maintain power system security.

The introduction of a backstop PV curtailment capability as a last resort would mean that on rare occasions, if all other options have been exhausted, distributed PV generation could be reduced if necessary to maintain power system security. The expected incidence of this action is very rare, as indicated in Figure 25. Backstop PV curtailment capabilities are already a requirement for new distributed PV installations in South Australia,

⁹³ AEMC (12 August 2021) Access, pricing and incentive arrangements for distributed energy resources, at <https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources>.

and AEMO is targeting implementation of the complete CMSL Framework in South Australia for this spring. Other available operational interventions were also applied before the first use of this mechanism on 14 March 2021.

The CMSL Framework will be consistent with strict requirements in the NER, which govern AEMO's operational actions in real time. Under the NER, AEMO intervenes in the market only when necessary to maintain power system security. The CMSL Framework, and AEMO's procedures, must therefore dictate that backstop distributed PV curtailment is only enacted after all other actions available to maintain power system security are exhausted, such as:

- Market-based responses harnessing flexible load and generation.
- Increasing enablement of essential security services (such as frequency control).
- Reducing or adjusting line flows.
- Recalling relevant planned line outages.
- Directing and/or instructing semi-scheduled and non-scheduled generation to reduce output.
- Constraining non-essential scheduled generation.
- Directing scheduled load in service (such as pumped hydro).

Market bodies, jurisdictions, networks, and consumer groups will need to collaborate on the detail of this mechanism and implement it through a consultative process.

Backstop PV curtailment capabilities can be relatively simple and low cost (as illustrated in the South Australian case study below), and can provide an initial starting point that can be built on to eventually develop the sophisticated DER response capabilities required for full market integration. However, if this simple backstop capability is not implemented soon, AEMO will not have adequate tools available to maintain power system security, and consumers will face an elevated risk of black system events, beyond the levels dictated by the NER.

The CMSL Mechanism is only suitable for use in rare circumstances, as a backstop to maintain power system security in unusual circumstances. It is not suitable, and must not be relied on, for managing daily market operation with high levels of DER. For this purpose, suitable market and regulatory frameworks will be required (as discussed above) to fully enable and incentivise consumers' DER to participate in the market.

In addition to providing the necessary tools for maintaining system security, the introduction of emergency PV curtailment capabilities provides a basic starting point from which more complex capabilities (such as dynamic operating envelopes and DSO frameworks, discussed above) can be established to support more sophisticated consumer engagement in market frameworks.

Case study: implementation of PV curtailment backstop in South Australia

An emergency backstop PV curtailment capability was introduced as a mandatory requirement of all new DER installations in South Australia on 28 September 2020. Distributed PV growth has continued to be robust, with 190 MW installed since that date (an average of 24 MW per month in 2021 to date, compared with 27 MW per month in 2020)⁹⁴. A total of 46 Relevant Agents (providers of this new service) have registered with the South Australian Government⁹⁵. Arguably, rather than slowing the market for distributed PV installations, the introduction of this new simple service requirement may have provided an initial stimulus for the market of new providers of future DER management services that will be required for full market integration of DER.

⁹⁴ As at 13 August May 2021, from Clean Energy Regulator postcode data for small-scale installations, at <http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations>.

⁹⁵ South Australian Government, List of Relevant Agents, at https://energymining.sa.gov.au/_data/assets/pdf_file/0020/370901/List_of_relevant_agents.pdf.

AEMO understands that development and implementation of this capability in South Australia occurred with zero cost pass through to consumers, and zero cost for the ongoing provision of the service from the majority of Relevant Agents. This is because the communication capabilities required to implement the emergency curtailment backstop were largely already in place to provide consumers with solar monitoring information, and under AS/NZS 4777.2:2015 inverters must have the capability to respond to disconnection and reconnection instructions. This functionality required a regulatory framework for activation.

Stimulating this market by providing real opportunities for new providers could accelerate the unlocking of new opportunities for consumers to deliver new services.

Opportunities emerging for consumers and stakeholders

Given the scale of this transition, and the breadth of new resources emerging in the market, a suite of new opportunities are expected to arise. The market frameworks for many emerging opportunities are not yet fully formed, so financial incentives may not yet be properly realised. AEMO aims to give stakeholders as much transparency as possible, providing an early view of where and when opportunities could emerge (based on the best currently available information) to facilitate efficient market development in this time of rapid change.

The key areas where AEMO identifies a likely growing need for services can be summarised as follows:

- **Frequency control services**, including FCAS, fast frequency response (FFR), and frequency recovery services (sustained active power increase or decrease in the period 5-10 minutes after a non-credible disturbance).
- **Load management**, including shifting or increasing of flexible loads in low load periods, and new sources of load, such as hydrogen production, electrification of industrial processes, and electrification of transport (see Section 6.3).
- **DER active management capabilities**, including active power management for DER, and delivery of power system services from DER.
- **Energy storage**, with sufficient capacity for daily cycling.
- **Generator and load flexibility**, including fast start capabilities, improved ramping and start up/shut down cycling abilities, and the ability to deliver system security services at lower minimum loading levels.

In many of these areas, market and regulatory frameworks do not yet properly value these services, so there may not be a return on investment in the present framework. The list above highlights the technical services that AEMO anticipates will be increasingly valuable in the future power system. Adaptation to market and regulatory frameworks is required to fully recognise the value of these new services; as noted, this is being progressed under the ESB's Post 2025 market design program.

6.2 Accelerated exit of thermal generation and decreasing plant reliability

The 2021 ESOO Central scenario considers the retirement of thermal generators at the 'expected closure year' reported by participants.

However, indications are that the exit of coal-fired and some gas-fired generation may occur sooner than currently reported:

- Robust growth in renewable energy connections (both DER and large-scale) is expected to continue, and will be supported by government policies such as the New South Wales Government Infrastructure Roadmap.
 - This growth will increase the instantaneous penetration of renewable generation – see Section 3.2.

- While some operators are adapting to increase the flexibility of their coal-fired generators⁹⁶, such growth in renewable generation is likely to impact their financial viability.
- Recent coal-fired generation reliability levels indicate a continued trend of relatively poor performance. While some improvements to generator reliability are expected in the near term, most generators are anticipating decreasing reliability in the longer term – see Section 3.4.
 - Operators have announced plans to reduce plant expenditure⁹⁷.
 - Numerous prolonged outages have been observed recently, including Unit 4 of Callide C Power Station in 2021 (Queensland) and Loy Yang A and Mortlake unit outages in 2019 (Victoria).
 - While this has not yet been observed, in future, operators may foreseeably choose not to return a unit to service if a catastrophic failure were to occur.
- Since the 2020 ESOO, the planned retirements of Yallourn Power Station (Victoria) and two units of Eraring Power Station (New South Wales) have been brought forward. The mothballing of one unit of Torrens Island B Power Station (South Australia) follows a similar trend, with AGL saying this decision was in response to challenging market conditions⁹⁸.

An accelerated exit may present reliability risks, where there is insufficient time for the development of new transmission and generation solutions. Uncoordinated exits may also have system security implications as there would be fewer synchronous units online to provide essential system services. These implications are one of the key operational considerations in AEMO’s Engineering Framework⁹⁹.

To test the implications of an accelerated exit of coal on reliability outcomes, AEMO developed a sensitivity where all coal-fired power stations are assumed to retire two years earlier than the currently provided expected closure year (excluding Liddell Power Station, which is within its three-year notice of closure period). This sensitivity has implications only for New South Wales and Victoria, in the ESOO’s 10-year horizon.

Figure 26 shows the results in comparison to the Central scenario.

In this sensitivity, with earlier retirements, reliability is forecast to deteriorate more rapidly over the next 10 years in New South Wales and Victoria. The analysis highlights a substantial reliability risk exists if coal exits in an uncoordinated manner, where plant withdrawal is not timed with appropriate investments in alternative generation or storage.

- In Victoria, the reliability standard is projected to be exceeded as soon as Yallourn Power Station retires. It is estimated that approximately 300-500 MW of new firm capacity would need to be available throughout the year to restore reliability below the reliability standard following an unanticipated early exit of the power station.
- In New South Wales, the reliability standard is projected to be exceeded as soon as Vales Point Power Station and the first unit of Eraring Power Station retire. Once all units of Vales Point Power Station and Eraring retire, expected unserved energy increases rapidly. It is estimated that approximately 2,500 MW of new firm capacity would need to be available throughout the year to restore reliability below the reliability standard by the time both power stations are closed.

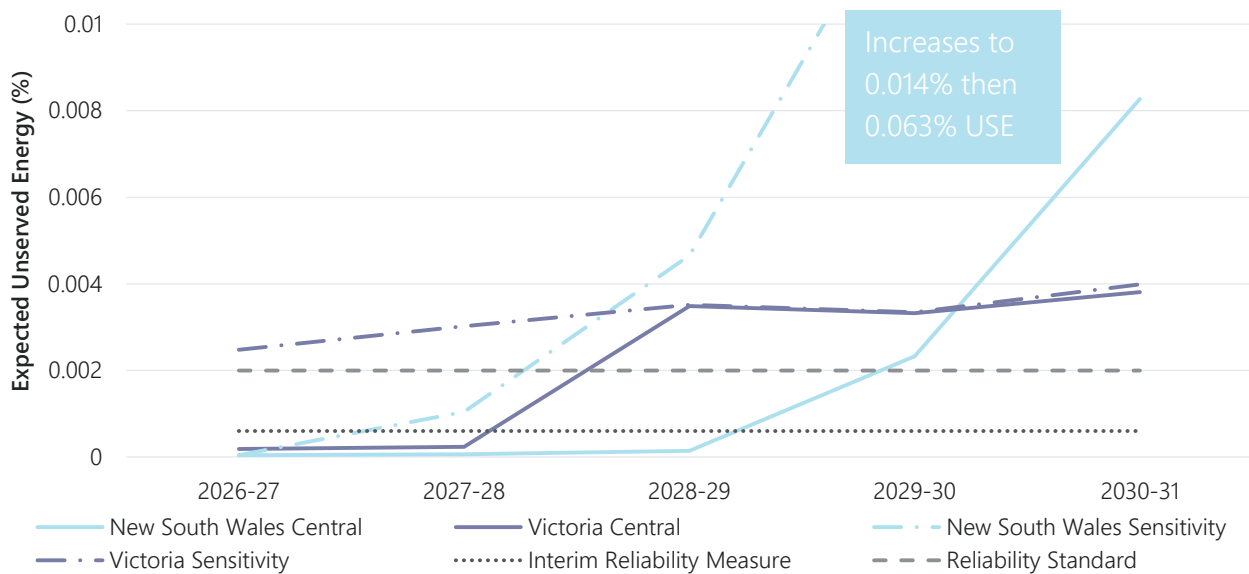
⁹⁶ As noted by AGL in its FY21 results announcement, at https://www.agl.com.au/-/media/aglmedia/documents/about-agl/asx-and-media-releases/2021/210812_fy21resultsfy22resultsandearningsguidance.pdf?la=en&hash=4BE20FDE0C5ABEC80530B4E7F787D0F6.

⁹⁷ As noted by Origin in its half-year 2021 results announcement, at <https://www.originenergy.com.au/about/investors-media/reports-and-results/half-year-results-20210218.html>.

⁹⁸ See AGL’s media release, at <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/july/agl-to-mothball-one-unit-at-torrens-b-in-south-australia>.

⁹⁹ See <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-july-2021-report.pdf>.

Figure 26 Reliability assessment in early coal retirements sensitivity, 2026-27 to 2030-31



The development of HumeLink, once committed, would significantly reduce the supply scarcity risk in New South Wales, and increase the NEM’s resilience to uncoordinated generator exits, by unlocking 2,000 MW of capacity from Snowy 2.0 (see Section 5.4).

Further, as part of the ESB’s Post 2025 market design reform pathways¹⁰⁰, mechanisms are being explored to manage the exit of coal-fired generation by giving incentives for the right mix of supply resources, to avoid reliability shocks to consumers.

6.3 Accelerated investment in hydrogen production and greater electrification growth

The potential development and connection of new electrical loads, through consumers switching from other fuels to electricity or through new industry, may result in significant growth in electricity consumption.

A low, or zero, emissions electricity grid may support the production of other primary energy fuels, such as hydrogen created through electrolysis. It also makes electrification an efficient alternative to other energy sources for energy consumers seeking to decarbonise their operations.

Through multi-sectoral modelling CSIRO and ClimateWorks Australia¹⁰¹ estimate that by 2050, approximately 90% of all newly electrified domestic loads will be from the transport and industrial sectors. In addition, fuel-switching from natural gas to electricity for residential heating is also anticipated, and there are already increasing signs of policy in this space¹⁰². Electrifying gas heating could introduce large electric heating loads in winter, potentially more significant than cooling loads in summer.

Table 9 below summarises the four main types of fuel-switching identified in the modelling that could materially grow electricity consumption in the NEM. Some of these loads will be more flexible than others, and therefore impact maximum and minimum operational demand differently.

¹⁰⁰ See <https://esb-post2025-market-design.aemc.gov.au/>.

¹⁰¹ CSIRO and ClimateWorks Australia, Multi-sector energy modelling, July 2021, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf.

¹⁰² Examples include the ACT Government no longer requiring new suburbs to have gas connections (see <https://www.cmtedd.act.gov.au/open-government/inform/act-government-media-releases/rattenbury/2020/now-were-cooking-with-electricity!-gas-no-longer-a-requirement-in-canberra-suburbs>) and the Victorian Government’s Gas Substitution Roadmap (<https://engage.vic.gov.au/help-us-build-victorias-gas-substitution-roadmap>).

Accommodating these new loads efficiently will require careful planning, combined with the right incentives, policies, or technologies to match inherent load flexibility with the need for grid flexibility, and maximise the value of any additional infrastructure investment that may be required.

Table 9 Assumed flexibility and implications of various forms of electrification and fuel-switching

Load	Description	Assumed flexibility
Hydrogen production	<p>Hydrogen production via electrolysis could become a very large consumer of electricity.</p> <p>The high capital cost of an electrolyser presently require high utilisation to minimise the effective cost of hydrogen, however this is projected to reduce, improving the opportunities for economically efficient flexible operations.</p>	<p>There are several electrolyser technologies, although at present there is substantial interest in proton exchange membrane (PEM) electrolysers due to their more flexible nature. The PEM electrolysers can respond very quickly, similarly to batteries. This means that they can rapidly turn on during times of plenty of supply and rapidly turn off during times where supply is tight.</p> <p>With the right market signals, electrolysers are likely to benefit the power system by increasing minimum demand, while largely avoiding high demand periods, shown in Figure 31.</p> <p>It is worth noting that some of the equipment in an electrolyser plant is expected to have a constant demand, including associated ammonia production facilities (for domestic or export use). Therefore, some impact on maximum operational demand would be expected and this could be material if hydrogen production becomes significant.</p>
EVs	<p>EVs are forecast to play a major role in the future of transport, and vehicle charging may be flexible as typically substantially fewer kilometres are driven in a day than the full charge, even for a short-range EV.</p>	<p>To 2030-31, as outlined in Section 2.3, EV charging has a weak contribution to maximum operational demand. Convenience-based charging drives this contribution, where the EV is plugged in when the owner gets home – during the peak period. However this contribution will grow with more uptake of EVs, if charging behaviour does not adapt</p> <p>To maximise the flexibility of EVs, the owners must be incentivised to charge at times that are suitable for the wider system, possibly with a low-cost technological solution to avoid the impost on the user. . AEMO assumes charging behaviour is incentivised to change at differing rates across the scenarios*.</p> <p>EVs could also play a role on the supply side of the grid using vehicle to grid technology.</p>
Business electrification	<p>Electrification of industrial loads could be a major source of electrification demand. This comes from fuel-switching away from oil, gas and coal (although not all use of fossil fuels can be readily electrified).</p>	<p>While there are some businesses that could participate in demand response schemes through WDR and DSP, overall, there is little limited opportunity for flexibility in this load. It is assumed that some businesses will participate in demand response schemes through WDR and DSP, proportional to the current level of demand response observed in the short term, but growing over time depending on scenarios.</p>
Residential electrification	<p>Electrification of residential loads is typically a smaller source of electricity consumption. However, 70% of this load is in Victoria, and most of this load occurs during winter. This strong regional and seasonal impact makes the importance of residential electrification much more significant, particularly during winter peak periods.</p>	<p>While some of the residential load would account for switching hot water services from gas to electricity (and could be managed by well-insulated hot water tanks) the majority comes from space heating requirements with flexibility.</p>

* See Section 3.3.5 of AEMO's 2021 IASR, at <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf>.

To help inform planning and decision-making, the remainder of this section highlights the potential for rapid growth in electricity consumption driven by fuel-switching, and possible implications for maximum and

minimum demand, showcased by the Hydrogen Superpower scenario and Strong Electrification sensitivity¹⁰³ outlined in Section 1.4.

6.3.1 The potential scale and seasonal impacts of electrification and fuel-switching

Both the Hydrogen Superpower scenario and the Strong Electrification sensitivity explore possible influences on the power system under a strong switch to electrification either directly (Strong Electrification sensitivity) or in combination with hydrogen produced by electrolysers (Hydrogen Superpower scenario).

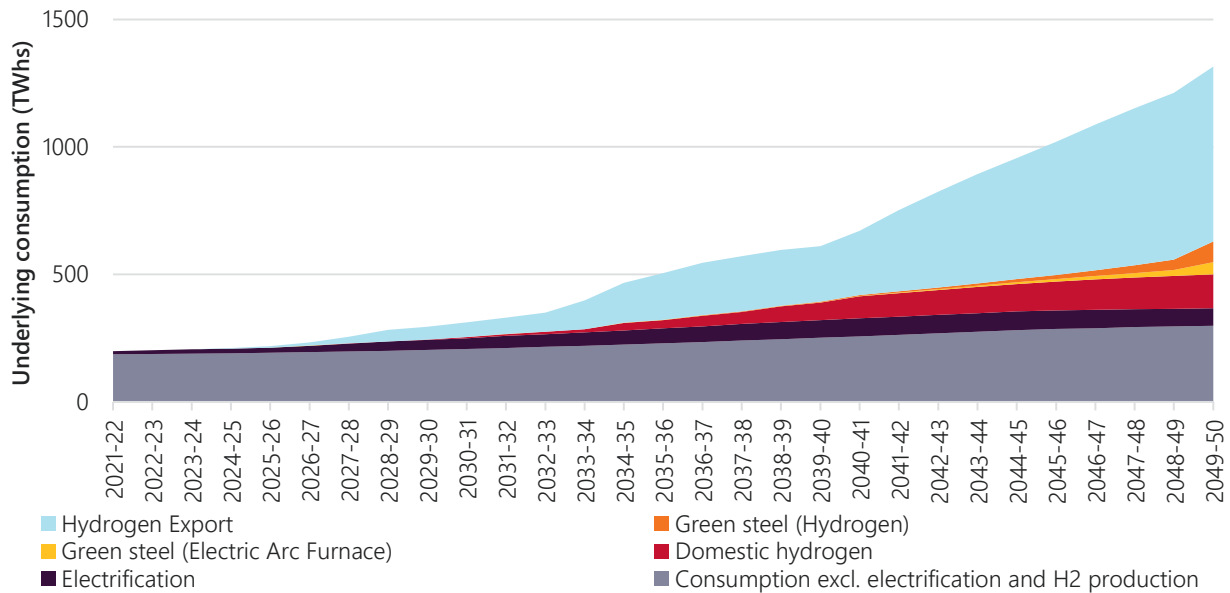
Hydrogen Superpower scenario

The Hydrogen Superpower scenario explores a future with substantial hydrogen production for local and international use, and introduces new energy-intensive, zero emissions industrial opportunities. The largest new consumers of electrical energy in this scenario are electrolysers creating green hydrogen as an export commodity. In this scenario, hydrogen exports are assumed to grow to 137 petajoules (PJ) by 2030, then accelerate rapidly to just over 1,800 PJ by 2050 (a similar level to current LNG exports from Queensland).

With strong assumed emissions reductions targets and growing hydrogen production capability from electrolysers, Australia’s opportunities for hydrogen-based exports in this future expand. The growth of a local manufacturing industry producing ‘green steel’¹⁰⁴ is an assumed beneficiary of local hydrogen production in the scenario, providing an opportunity to produce and export a high-value processed commodity to complement raw hydrogen products. The green steel is also intended to represent a broader opportunity for energy-intensive minerals processing.

Figure 27 shows the projected scale of growth for export-focused industries relative to other NEM consumption in the Hydrogen Superpower scenario.

Figure 27 Relativity of new electricity demand in the Hydrogen Superpower scenario, 2021-22 to 2050-51



By 2030, the growth of new hydrogen industries (green steel and export) is projected to account for around 17% of total electricity consumption, slightly more than the forecast influence of electrification. The additional

¹⁰³ The Strong Electrification sensitivity is a variant on the Hydrogen Superpower scenario where hydrogen cost reductions are not successful and the decarbonisation is focused on electrification. More information can be found in Section 1.4.

¹⁰⁴ Green steel is made using direct reduced iron (DRI), where the furnace is filled with a reducing gas produced using renewable resources, such as green hydrogen. Traditional blast furnaces achieve higher temperatures, but the use of the DRI process enables the use of lower temperature electric arc furnaces, achieving substantial reductions in carbon emissions.

electricity energy consumption for hydrogen production is largely for export as ammonia, although the potential for domestic hydrogen use and a large green steel industry is a growing long-term opportunity. In total, an electricity consumption increase of 73 TWh is forecast in this scenario by 2030-31 (approximately 40% above current NEM operational consumption), in contrast to the 4 TWh (approximately 2%) reduction in operational sent out consumption by 2030-31 compared with today that is forecast in the Central demand outlook.

By 2050, hydrogen-related demand could be five times larger than current NEM consumption, and around 150 TWh of new underlying domestic electricity consumption is projected purely from transport and industrial electrification.

With the availability of low-cost hydrogen, the Hydrogen Superpower scenario forecasts greater opportunity for existing residential heating loads to convert to hydrogen rather than electrification. As a result, the scenario forecasts only about 30% of residential gas consumption is electrified by 2050 (5 TWh).

Strong Electrification sensitivity

The Strong Electrification sensitivity has similar decarbonisation ambitions to the Hydrogen Superpower scenario, but does not have the same opportunity to switch fuels to hydrogen consumption or leverage as many energy efficiency savings. Consequently, very high electrification levels in industry, transport, and residential heating are projected over time. No new export opportunities are assumed.

By 2030-31, up to 5 TWh of residential electrification is projected across the NEM – around 30% of the total potential identified by 2050. Similarly, by 2030-31, transport electrification is forecast to consume around 14 TWh (approximately 17% of potential) and business electrification is forecast to consume around 62 TWh (60% of potential).

By 2050, increased electricity consumption due to electrification could be as high as 200 TWh (84 TWh from EVs, 100 TWh from electrification of business loads, and 15 TWh from residential electrification). Even with nearly 100% electrification of building heating projected by 2050, total additional consumption from this sector only amounts to 7.5% of the total electrification.

Impact of fuel-switching on summer and winter maximum and minimum demand

The impact of fuel-switching (that is, electrification or hydrogen production for domestic use) on maximum and minimum operational demand is influenced by a range of factors, such as:

- Relative heating appliance efficiency (both existing gas appliances and electrical alternatives, including efficiency improvements over time)¹⁰⁵
- Investments to improve building thermal efficiencies
- Presence of seasonal storage
- Flexibility of load
- Demand management incentives (such as pre-heating/pre-cooling techniques¹⁰⁶)
- Tariff reform.

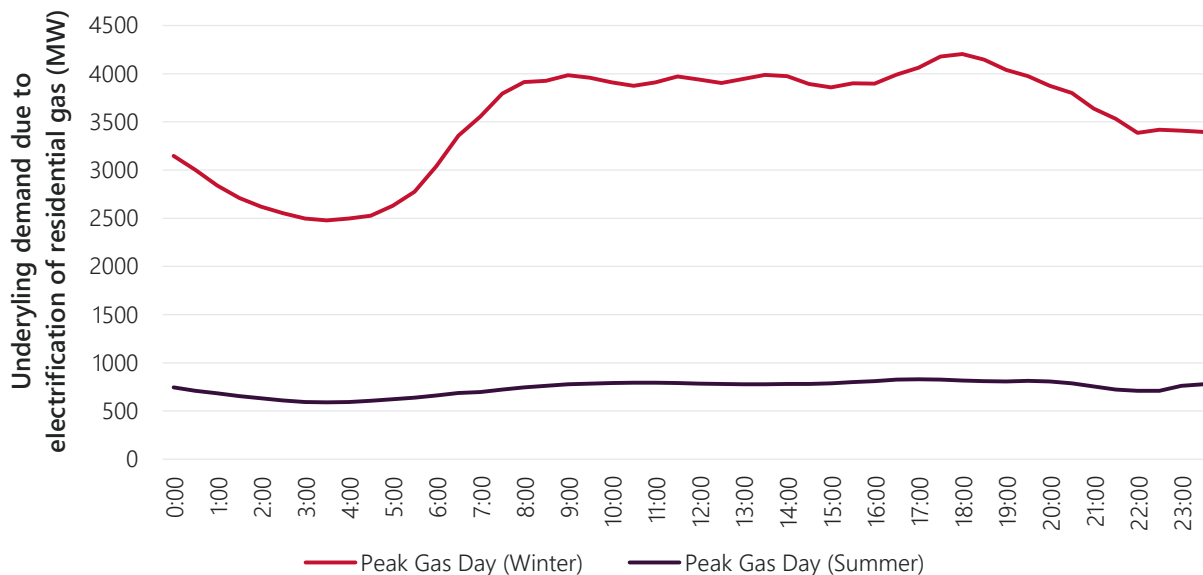
The seasonal nature of building heating demand, largely servicing the residential sector, means electrification of gas heating could significantly impact both the magnitude and timing of maximum operational demand. This is despite being projected to account for no more than 7.5% of total new consumption from fuel-switching by 2050 under either the Hydrogen Superpower scenario or Strong Electrification sensitivity.

¹⁰⁵ The efficiency (Coefficient of Performance) of heat pumps varies with outside temperature; during colder weather not only is there increased need for heating, but its efficiency drops. This effect has not been captured in AEMO's forecasts, although it is expected to be less material in the moderate Australian winters compared with some international studies.

¹⁰⁶ Pre-heating techniques might reduce the peak demand impact of electrified appliances, although this relies on housing with high thermal efficiency as well as behavioural change (either explicit or enabled through increased digitisation).

The full electrification of Victorian residential gas demand could contribute up to 4,200 MW of additional underlying electricity demand on what would have been a peak gas demand day in winter, demonstrated in Figure 28, compared with around 830 MW on a peak gas demand day in summer. This is a difference of 3,370 MW.

Figure 28 Potential additional electricity underlying demand under full electrification of Victorian gas demand



However, these increases in seasonal operational demand are not expected to result in a corresponding increase in *maximum* operational demand in Victoria, as the summer 10% POE maximum demand is currently approximately 2,200 MW higher than the winter maximum in the region (see Appendix Section A5.2). This means there is substantial scope for additional winter peak demand before the annual peak might shift to winter. For example, Figure 29 contrasts peak demand forecasts for the current system against the forecast additional demand due to electrification in 2050. The current summer peak is notably higher than the winter peak, so even with a large additional demand in winter, the annual peak demand may remain the same.

AEMO forecasts that by electrifying around half of the residential heating gas demand, Victoria could become winter peaking, and by 2050, the winter 10% POE maximum demand in the Strong Electrification scenario with nearly 100% residential electrification could be up to approximately 1,000 MW higher than the summer 10% POE peak. Increased focus will be placed on the impact of electrifying heating loads on seasonal demand peaks, particularly for regions where it is of greatest relevance.

Figure 29 Example daily traces showing peak seasonal conditions for Victoria contrasting current system demand against the forecast additional demand due to electrification, Net Zero 2050, 10% POE conditions

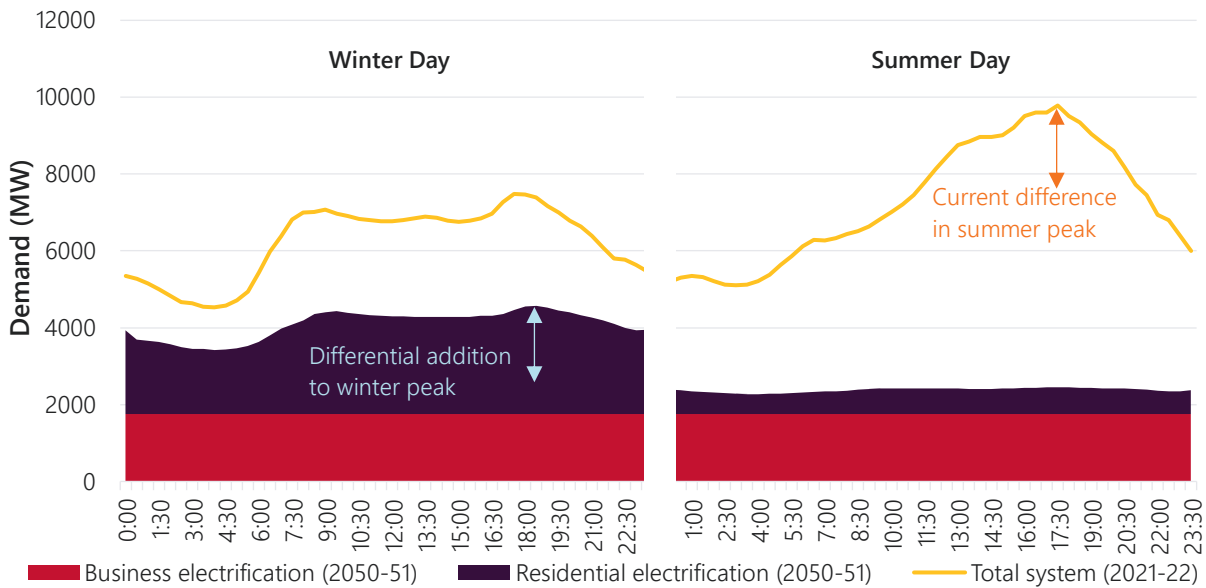


Figure 30 further shows that with high levels of electrification (based on the Strong Electrification sensitivity) the timing of Victoria’s maximum operational demand is projected to change from occurring in summer to occurring in winter. All forms of electrification could contribute as much as 9,000 MW of additional underlying demand in certain time periods in the Victorian winter. Examining the peak demand, 45% of the electrification load comes from residential, 30% comes from business and 25% comes from transport. The charging needs of EVs may potentially have substantial impact on the peak demand. In the Strong Electrification sensitivity, a relatively high rate of coordinated charging was assumed. If all EVs only used the convenience charging profile, the peak demand would have been approximately 4,400 MW higher. Other sources of electricity demand, energy efficiency, distributed PV generation, among other factors, all contribute to the final maximum demand forecasts.

In the Hydrogen Superpower scenario, more of this residential heating demand is met through use of hydrogen, produced by electrolyzers. While still ultimately adding operational demand to the system, one advantage that electrolyzers offer is a source of increased load flexibility. Electrolyzers are expected to be able to operate with a relatively wide technical envelope, operating at capacity while VRE is plentiful, yet avoiding operation during the highest price periods to keep hydrogen production costs low. This flexibility is expected to reduce the impact on maximum operational demand and consequently minimise large-scale infrastructure investment requirements.

Figure 31 shows the flexibility in hydrogen electrolyser consumption patterns on average and selected days. Electrolyser consumption is avoided during high-price periods associated with maximum demand, whereas electrolyzers increase consumption substantially during minimum demand periods, demonstrating the potential for load flexibility to help manage high DER penetration (see Section 6.1).

As shown in Figure 30, under the Hydrogen Superpower scenario, a shift to winter being the defining season for maximum operational demand may be avoided with low cost and emissions free alternatives such as hydrogen, and greater flexibility of the electrolyzers to avoid peak demand periods.

Figure 30 Victorian seasonal peak demand forecasts for the Hydrogen Superpower scenario and the Strong Electrification sensitivity, 10% POE conditions

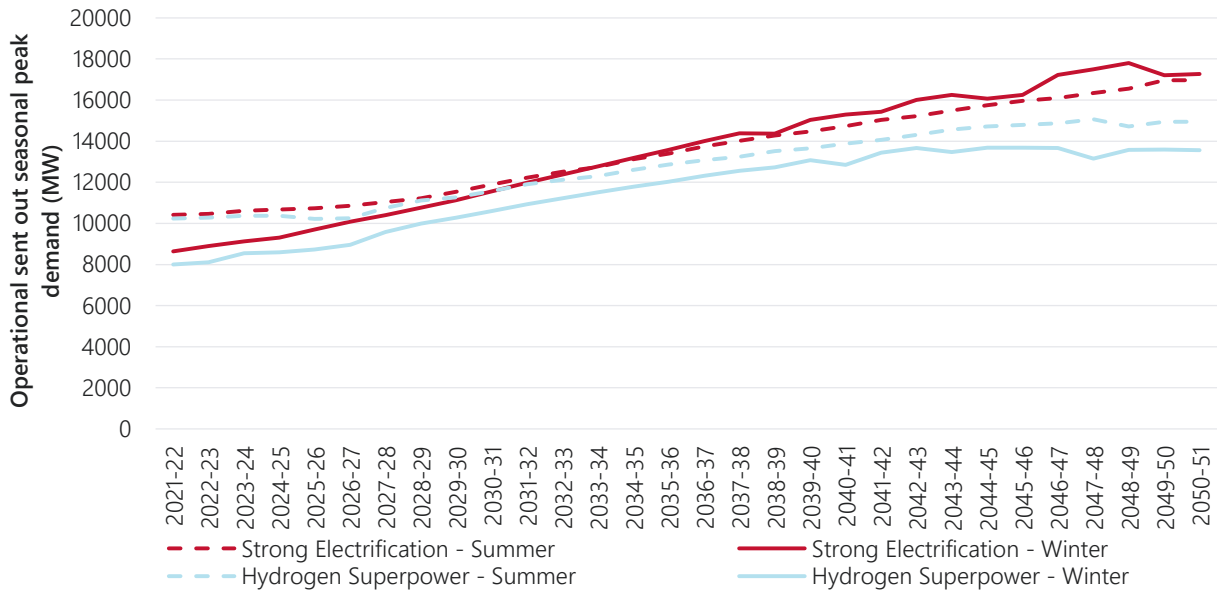
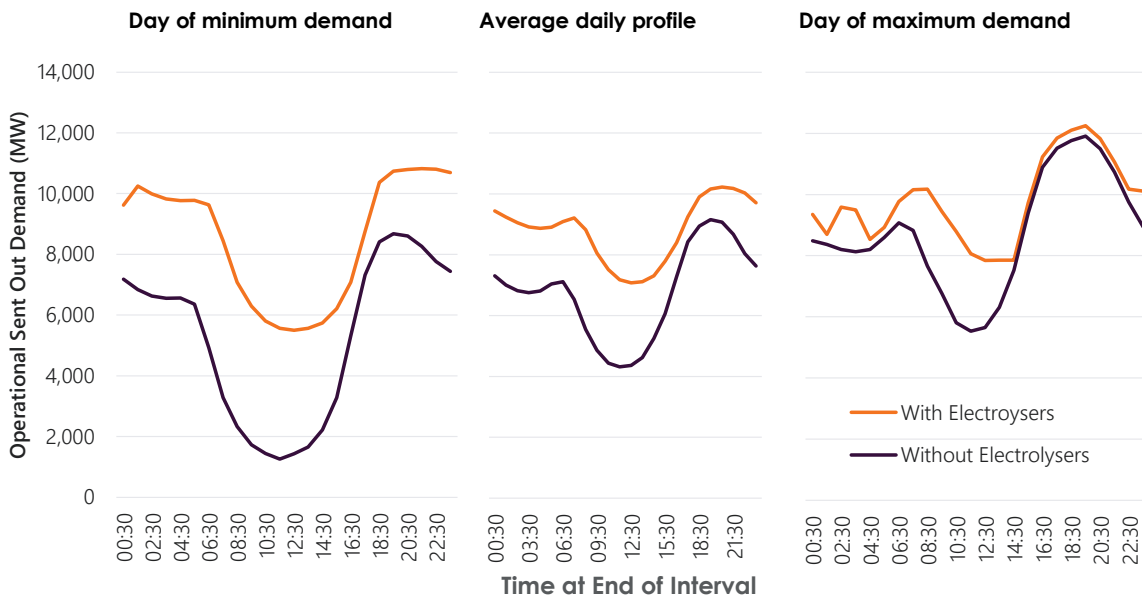


Figure 31 Indicative hydrogen electrolyser impacts on selected days, Queensland 2030-31



Embedded energy storages and new tariff design, coupled with strong digitalisation, will also enable consumers to reduce their own grid consumption during peak demand periods. For example, charging infrastructure and tariff designs to encourage efficient EV charging will also become increasingly important in minimising the impact of these new electrical loads, and potentially to support broader household energy management, with or without hydrogen – see the 2021 IASR.

A1. New South Wales outlook

The following sections present:

- Operational consumption, maximum demand, and minimum demand outlooks for New South Wales for all five IASR scenarios to 2050-51.
- Supply adequacy assessments for New South Wales over the next 10 years, for the Slow Change, Central, and Hydrogen Superpower scenarios, in the absence of any further supply developments.

A1.1 Annual consumption outlook – New South Wales

Figure 32 shows the component forecasts for operational consumption in New South Wales under the Net Zero 2050 scenario.

Both the Net Zero 2050 and Steady Progress scenarios were selected as the Central demand scenarios for the supply adequacy assessments in this ESOO (see Section 1.4). Figure 32 shows the Net Zero 2050 scenario forecast to 2050-51 because this scenario provides insight into the potential consumption impacts of industrial electrification associated with an economy-wide decarbonisation Net Zero emissions objective by 2050, and is therefore informative for stakeholders that have aspirational or legislated goals to achieve this objective.

It shows that in the Net Zero 2050 scenario, AEMO forecasts:

- 2021-22 to 2030-31 (1-10 years) – continued strong growth of distributed PV, and a lower forecast from the business mass market sector.
- 2031-32 to 2040-41 (11-20 years) – consumption growing strongly due to growth in the business sector and electrification growth from transport and the business sectors, despite continuing growth in distributed PV and energy efficiency.
- 2041-42 to 2050-51 (21-30 years) – similar growth trends continuing from the preceding decade, with a step up of electrification in the business sector and the emergence of hydrogen production for domestic usage, seeing consumption growing strongly from the mid-2040s.

Figure 32 New South Wales electricity consumption, actual and forecast, 2013-14 to 2050-51, Net Zero scenario

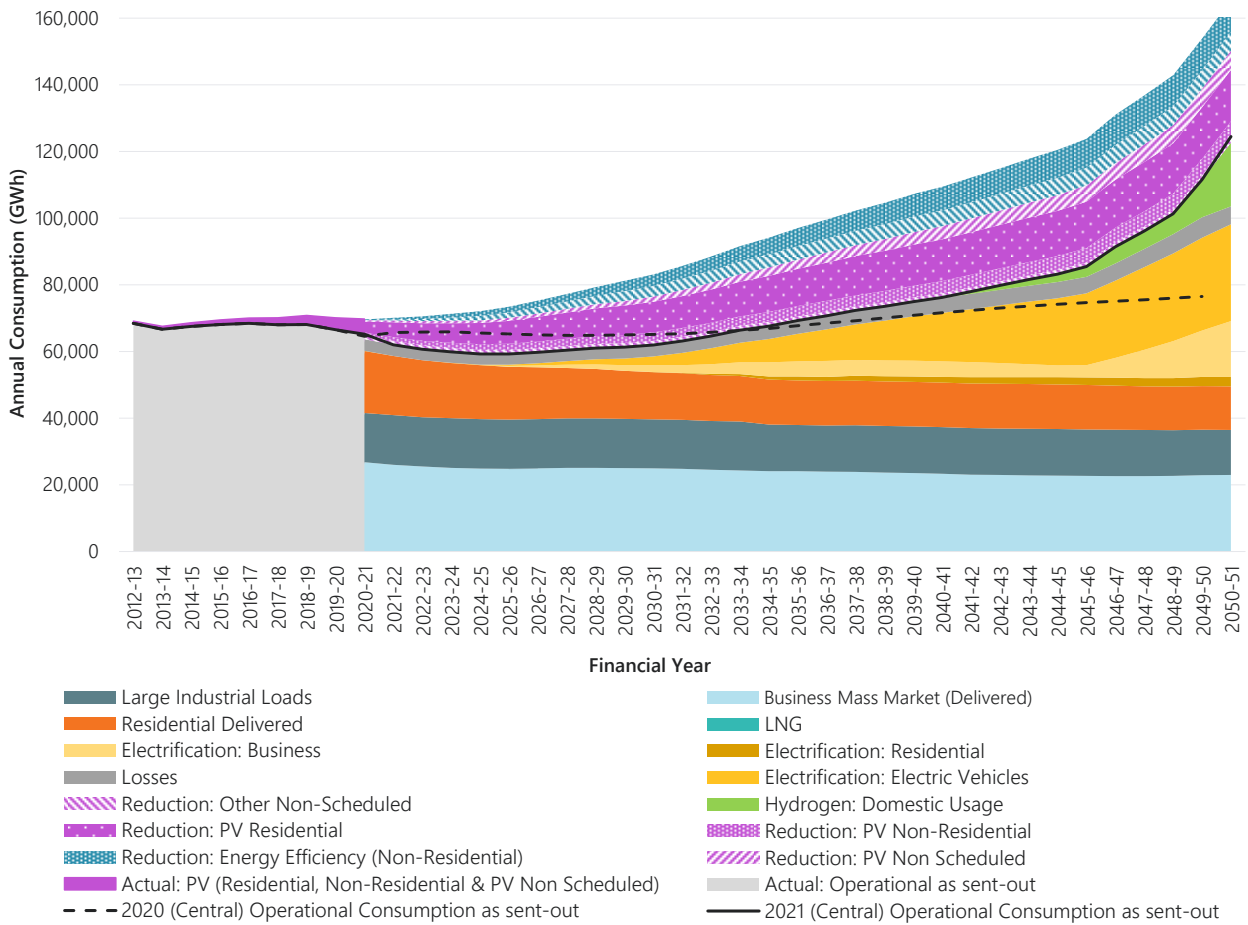
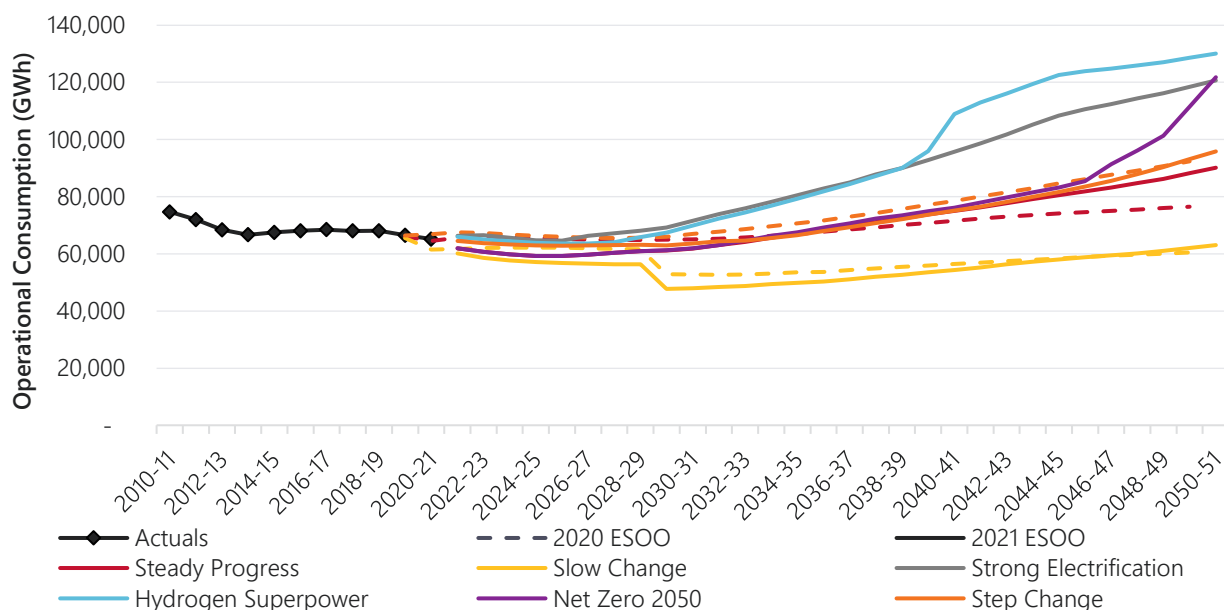


Figure 33 shows all the scenarios, highlighting that:

- Electrification dominates the growth trajectories of both the **Strong Electrification** sensitivity and **Hydrogen Superpower** scenario with only domestic Hydrogen production in the latter, shown as additional load.
- **Slow Change**, with large industrial load closure risks, short-term rapid distributed PV growth and no electrification sees it as the lowest scenario in consumption terms.
- **Step Change** has a slightly lower long-term trajectory than Net Zero 2050, due to a higher PV forecast as well as lower electrification.
- **Steady Progress**, while tracking closely to the Net Zero 2050 scenario, has relatively limited long-term electrification impacts that mean consumption is forecast to be about 15 TWh lower than in Net Zero 2050 by 2050-51.

Note that Figure 33 does not include all consumption related to hydrogen export and green steel production, as the regional allocation of hydrogen exports will be an outcome of the long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 33 New South Wales operational consumption in GWh, actual and forecast, 2010-11 to 2050-51, all scenarios



A1.2 Maximum demand outlook – New South Wales

- Short term (0-5 years) – maximum operational demand is expected to decrease over the next few years due to lower demand from the business mass market sector, and to a lesser extent sustained uptake of distributed PV.
- Medium to long term (5-30 years):
 - Maximum operational demand is forecast to grow due to increased EV uptake and electrification, with EVs and electrification contributing to nearly 20% of one-in-two year maximum operational demand by 2040-41 in the Net Zero 2050 scenario. Large increases in industrial electrification near the end of the forecast horizon result in a noticeable increase in maximum operational demand in the Net Zero 2050 scenario.
 - Conversely, scenarios such as Step Change, that have stronger electrification ambitions but also assume more coordinated EV charging, see a forecast reduction in maximum operational demand from 2034-35 compared to the Net Zero 2050 and Steady progress scenarios.
 - With the risk of large industrial load closures considered in the Slow Change scenario, a drop in maximum operational demand in 2029-30 is forecast.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below; these will be presented in future versions of the demand forecasts as an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 34 Forecast summer 10% POE maximum operational demand (sent-out) by scenario, New South Wales

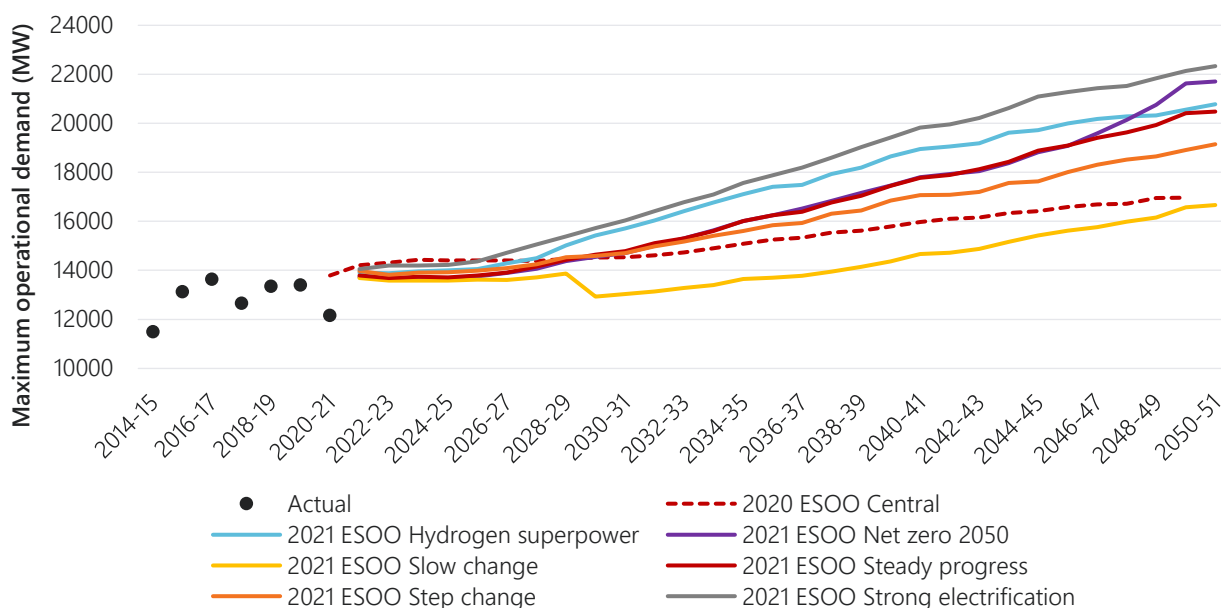


Table 10 shows maximum summer and winter operational demand (sent-out) forecasts for 10% POE and 50% POE for the Net Zero 2050 scenario.

Around 2034-35, New South Wales is forecast to become winter peaking in one-in-two year conditions (the 50% POE forecast maximum operational demand for winter is higher than the summer).

For 10% POE outcomes, the summer forecast remains higher than winter as the cooling demand on extreme summer days is higher than the heating demand on the coldest winter days.

Table 10 Forecast maximum operational demand (sent out) in New South Wales, Net Zero 2050 scenario (MW)

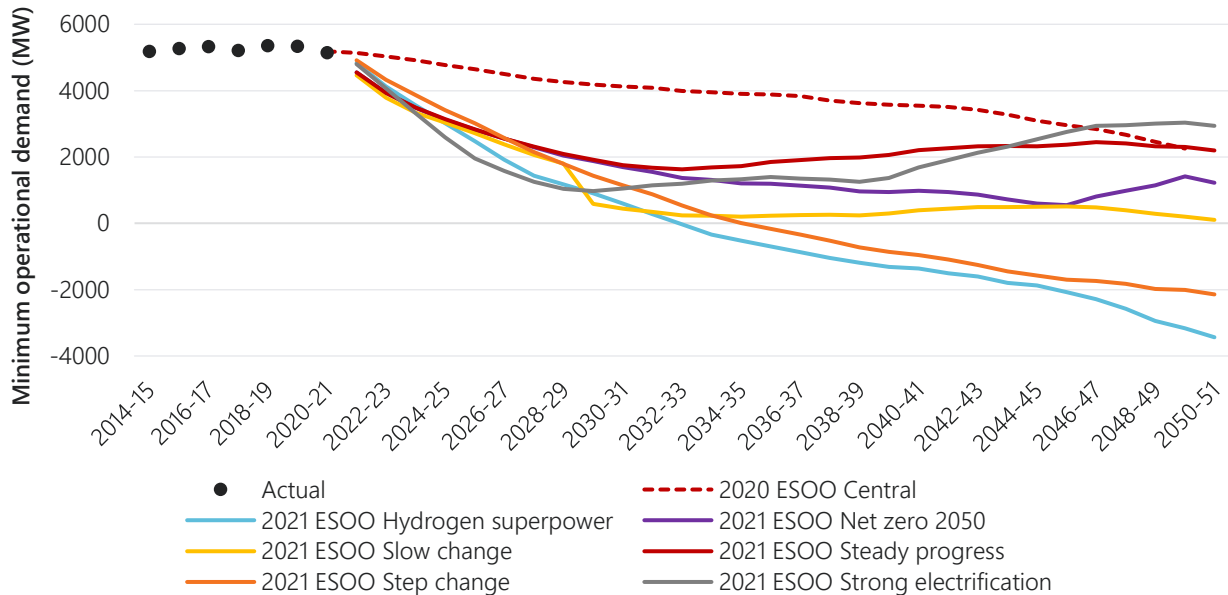
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2021-22	13,719	12,688	2022	12,631	11,962
2025-26	13,750	12,595	2026	12,932	12,215
2030-31	14,699	13,395	2031	13,884	13,210
2040-41	17,807	16,022	2041	17,009	16,271

A1.3 Minimum operational demand outlook – New South Wales

- Short term (0-5 years) – minimum operational demand is expected to decrease at a faster rate for all scenarios compared to the 2020 ESOO, due to an increased forecast uptake of distributed PV.
- Medium to long term (5-30 years):
 - Minimum operational demand is forecast to continue to decline for the next decade across all scenarios, after which non-coordinated EV uptake, battery capacity changes, and electrification have a greater impact on the changes in minimum demand (see Figure 35).

- The Hydrogen Superpower and Step Change scenarios forecast negative minimum operational demand events occurring from the early 2030s, representing opportunities for market-based solutions such as coordinated storage and EV charging, and for additional scheduled loads such as new pumping load, to increase operational demand during these minimum demand events.

Figure 35 Forecast annual 50% POE minimum operational demand (sent-out) by scenario, New South Wales



A1.4 Supply adequacy assessment – New South Wales

Expected changes to existing and committed supply in New South Wales include:

- Between summer 2020-21 and 2021-22, 1,066 MW of additional VRE generation is expected to become operational and 50MW of large-scale battery is expected to be connected¹⁰⁷.
- In 2023-24, the 750 MW Kurri Kurri gas generator is assumed to connect, as is the 2,040 MW Snowy 2.0 pumped hydro generator from 2025-26 to 2026-27. Both are Federal Government policy commitments.
- The 2,000 MW Liddell Power Station is scheduled to retire between April 2022 and April 2023, followed by the 1,320 MW Vales Point B Power Station in 2029-30 and the 720 MW Eraring Unit 4 in 2030-31.

Figure 36 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on capacity during typical summer conditions.

¹⁰⁷ Measured as summer typical capacity.

Figure 36 New South Wales assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31

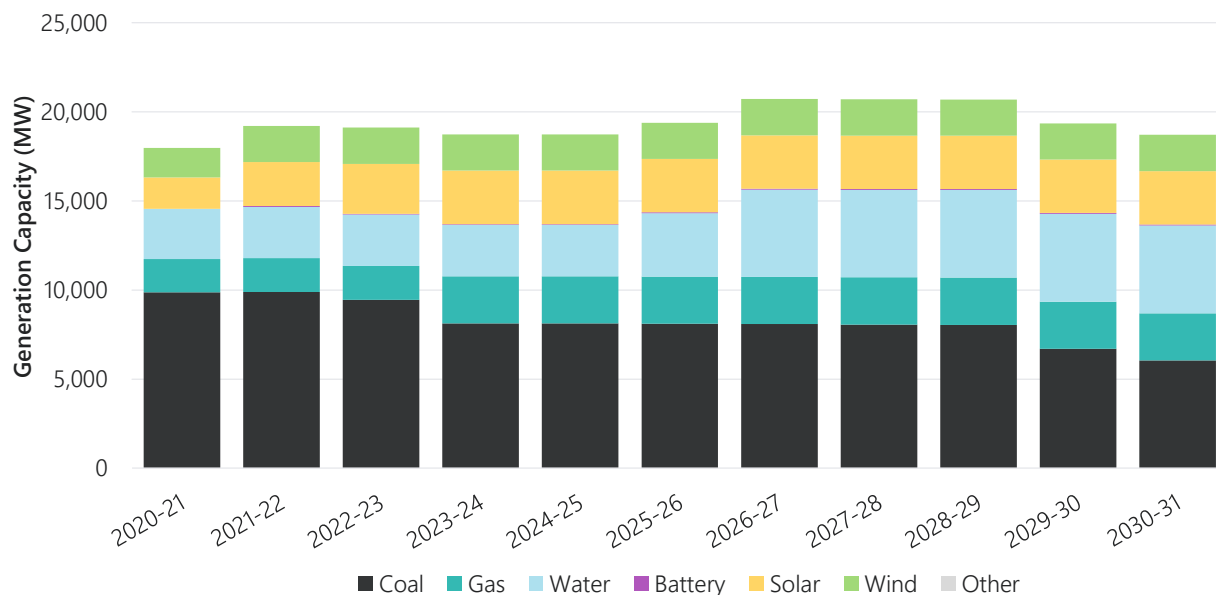
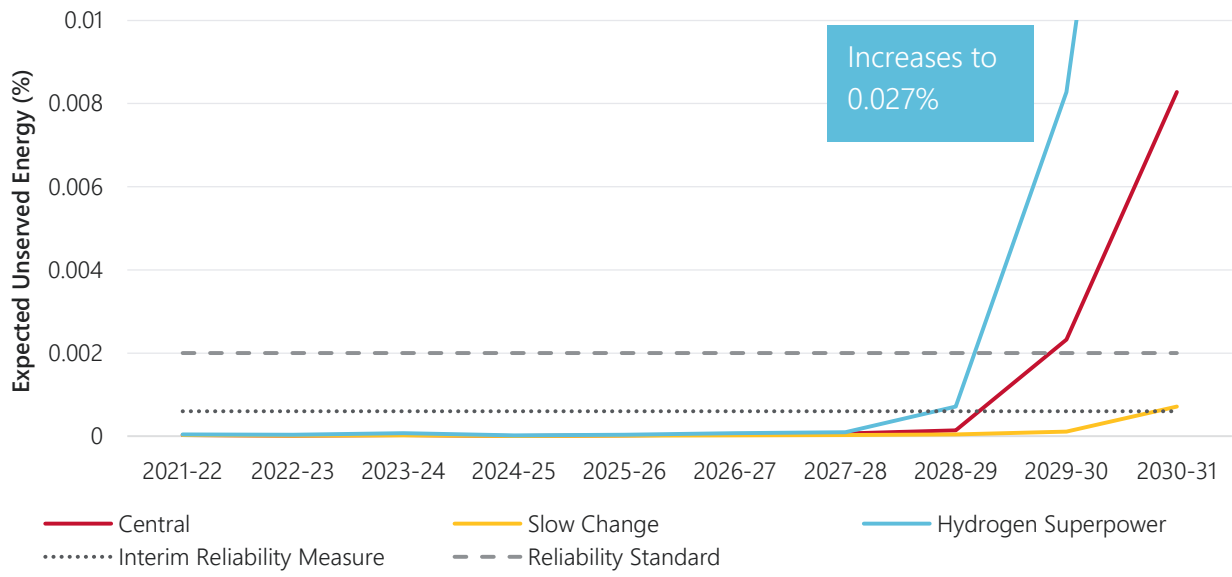


Figure 37 shows the forecast USE for New South Wales under the three scenarios¹⁰⁸:

- Low levels of expected USE are forecast under all three scenarios before 2028-29, when Vales Point Power Station and then Eraring Unit 4 are assumed to retire.
- USE is no longer forecast to increase above the IRM after the retirement of Liddell Power Station, primarily due to newly committed gas and VRE generation.
- Additionally, the VNI Minor and QNI Minor upgrades and peak demand forecast reductions all contribute to a lower reliability risk.
- Following the retirement of Vales Point in 2029-30, expected USE increases substantially, to above the reliability standard under the Central and Hydrogen Superpower scenarios. There are multiple generation, storage and transmission projects, well progressed, that would help mitigate these supply scarcity risks. Expected USE in the Hydrogen Superpower scenario demonstrates that under this scenario additional supply developments would take place to ensure economic viability of hydrogen industries.
- Expected USE remains low across all years in the Slow Change scenario, due to the lower forecast peak demand.

¹⁰⁸ Both the Net Zero 2050 and Steady Progress scenarios are considered as the Central scenario.

Figure 37 New South Wales USE forecast by scenario



A2. Queensland outlook

The following sections present:

- Consumption, maximum demand, and minimum demand outlooks for Queensland for all scenarios out to 2050-51.
- Supply adequacy assessments for Queensland over the next 10 years for the Slow Change, Central and Hydrogen Superpower scenarios, in the absence of any further supply developments.
- An assessment of when operational minimum demand will reach thresholds for secure operation of the power system in Queensland.

A2.1 Annual consumption outlook – Queensland

Figure 38 shows the component forecasts for operational consumption in Queensland under the Net Zero 2050 scenario.

Both the Net Zero 2050 and Steady Progress scenarios were selected as the Central demand scenarios for the supply adequacy assessments in this ESOO. Figure 33 shows the Net Zero 2050 scenario forecast to 2050-51, as this scenario provides insight into potential consumption impacts of industrial electrification associated with an economy-wide decarbonisation Net Zero emissions objective by 2050, and is therefore informative for stakeholders that have aspirational or legislated goals to achieve this objective.

The figure shows that in the Net Zero 2050 scenario, AEMO forecasts:

- 2021-22 to 2030-31 (1-10 years) – continued strong growth of distributed PV and a lower forecast from the business mass market sector, coupled with stable forecasts for large industrial load and LNG.
- 2031-32 to 2040-41 (11-20 years) – consumption growing strongly due to growth in business sector consumption and electrification growth from the transport and the business sectors, despite continuing growth in distributed PV and energy efficiency. The residential sector grows to approach being a net exporter of PV, with distributed PV nearly offsetting (at an annual level) the electricity delivered from the grid.
- 2041-42 to 2050-51 (21-30 years) – similar growth trends continue from preceding decade, coupled with a step up of electrification in the business sector, strongly growing consumption from mid 2040s with the emergence of hydrogen production for domestic usage.

Figure 38 Queensland electricity consumption, actual and forecast, 2013-14 to 2050-51, Net Zero scenario

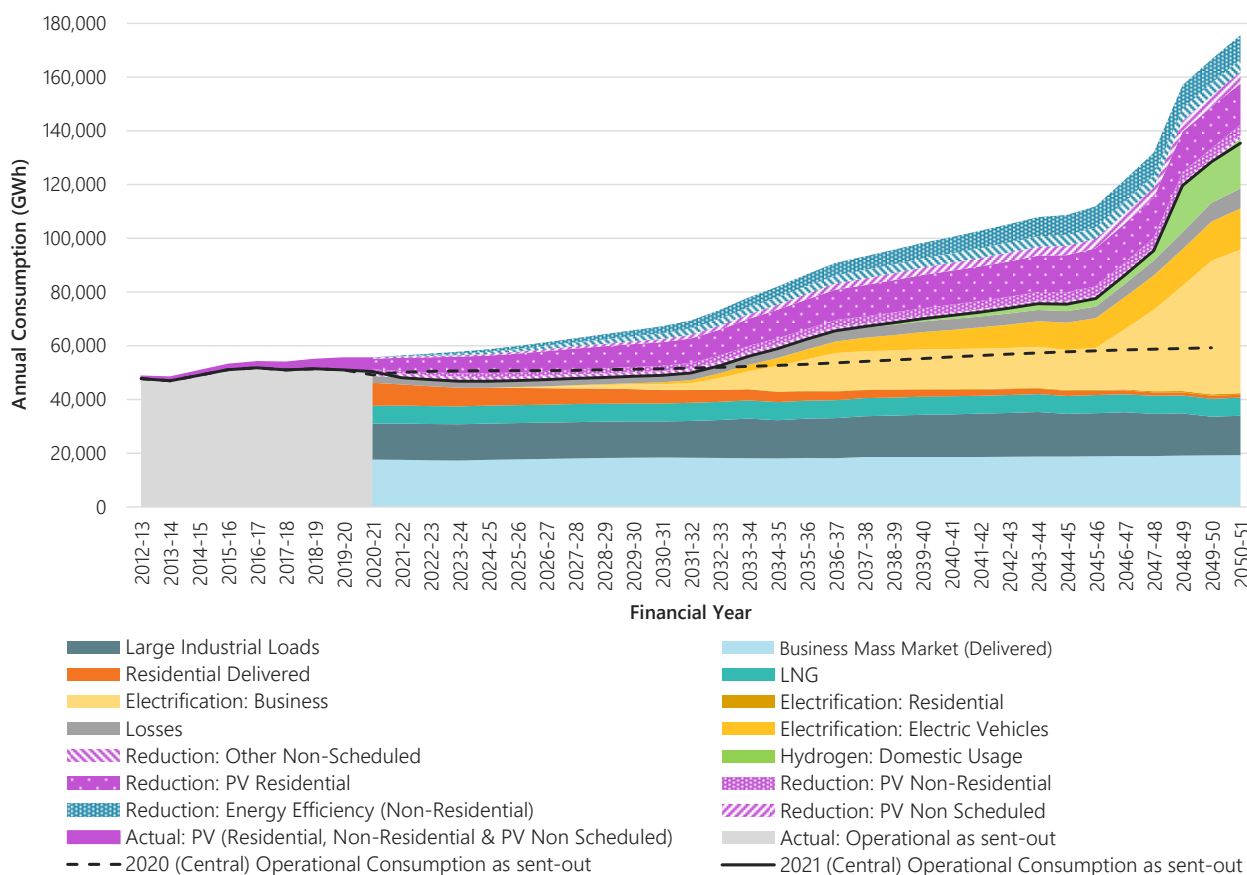
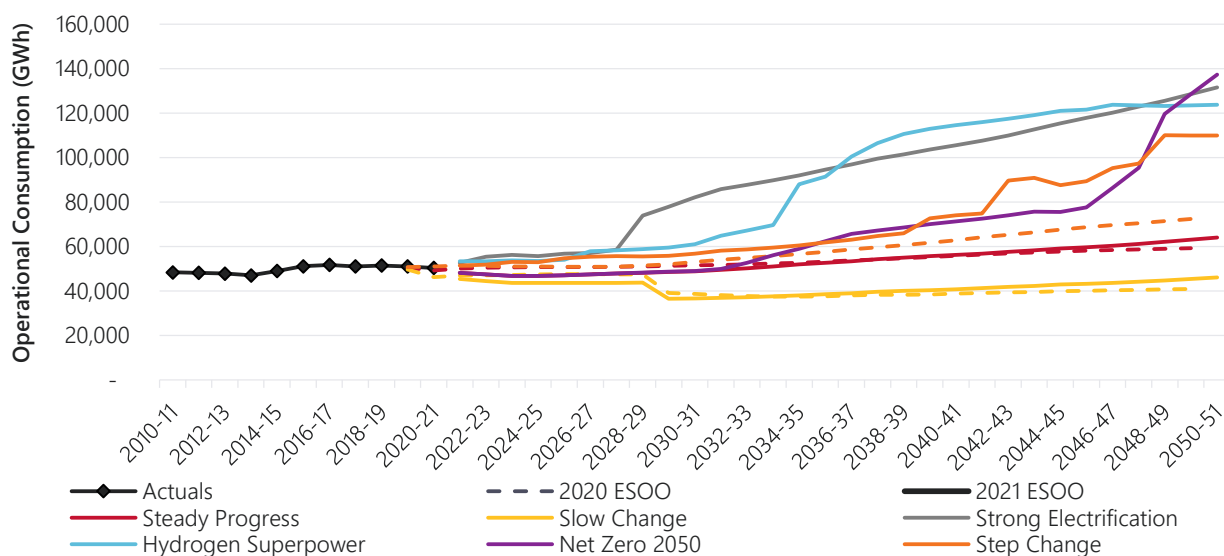


Figure 39 shows the consumption forecast across the scenarios, highlighting:

- Electrification dominates the growth trajectories of both the **Strong Electrification** sensitivity and **Hydrogen Superpower** scenario, with only domestic hydrogen production shown in the latter, and Queensland forecast to have the highest NEM hydrogen production for domestic and green steel uses.
- **Slow Change**, with large industrial load closure risks, short-term rapid distributed PV growth and no electrification, has the lowest consumption of the scenarios.
- **Step Change** has a higher short-term forecast than Net Zero 2050 owing to larger electrification, but its higher PV forecast and the later ramp up of electrification in Net Zero 2050 result in a lower long-term trajectory towards the end of the forecast horizon.
- **Steady Progress**, while tracking closely to Net Zero 2050 in the first 10 years, has limited long-term electrification impacts which means consumption is forecast to be about 60 TWh lower than in Net Zero 2050 by 2050-51.

Note that Figure 39 does not include consumption related to hydrogen export and green steel production, because the regional allocation of hydrogen exports will be an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 39 Queensland operational consumption in GWh, actual and forecast, 2010-11 to 2050-51, all scenarios



A2.2 Maximum demand outlook – Queensland

- Short term (0-5 years) – maximum operational demand is expected to grow at a slightly lower rate compared to the 2020 ESOO, as a result of lower forecast growth in the business mass market sector.
- Medium to long term (5-30 years):
 - Maximum operational demand is expected to see strong growth, due to increases in both residential and business load.
 - Electrification is also expected to be a major contributor to maximum operational demand, forecast to contribute to nearly 14% of one-in-two-year maximum operational demand by 2040-41 in the Net Zero scenario. The Strong Electrification sensitivity forecasts a rise in maximum operational demand from the late 2020s onwards, driven by electrification of major industrial processes.
 - Around the same time, risks of large industrial load closures result in a reduction in forecast maximum operational demand in the Slow Change scenario.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below; these will be presented in future versions of the demand forecasts as an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 40 Forecast summer 10% POE maximum operational demand (sent-out) by scenario, Queensland

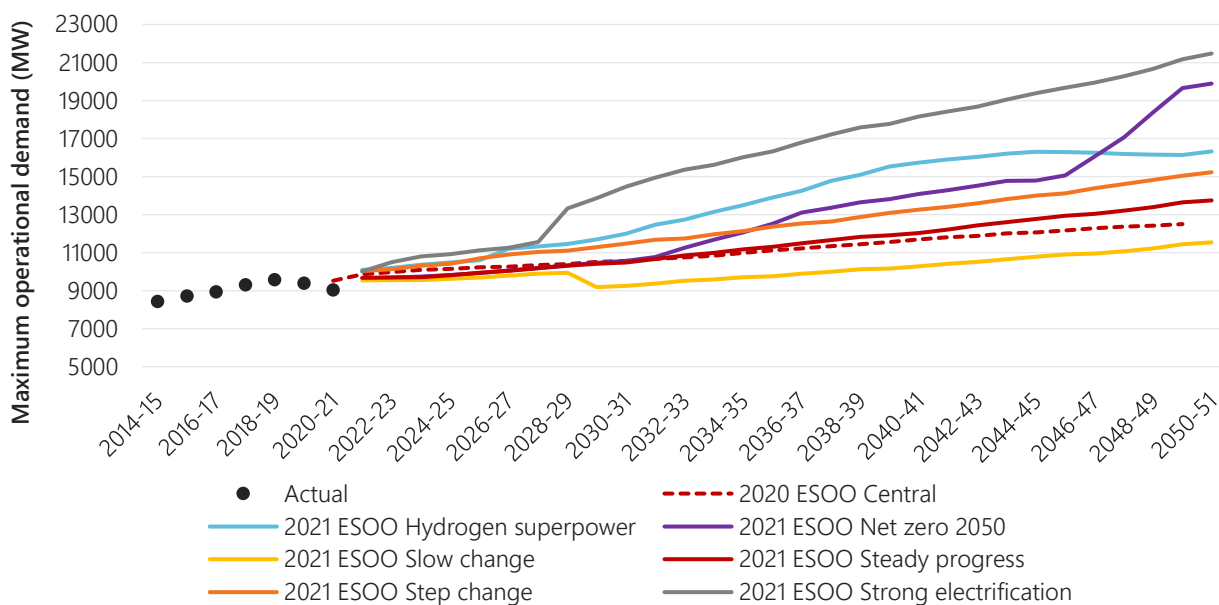


Table 11 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Net Zero 2050 scenario. Maximum operational demand in Queensland is forecast to keep occurring in summer over the forecast horizon.

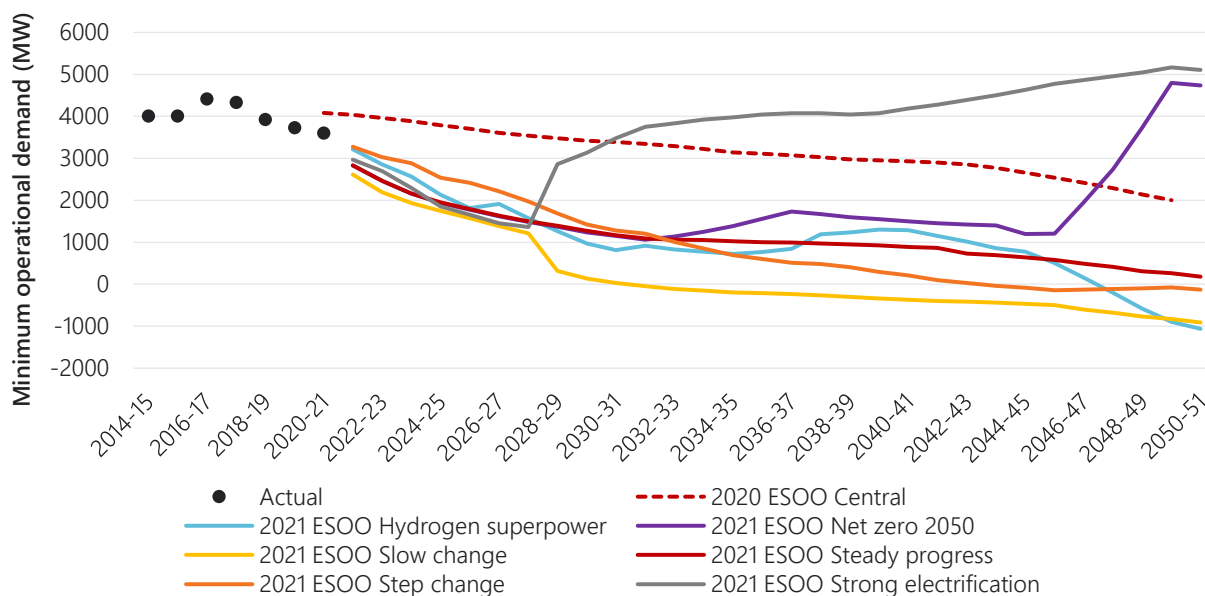
Table 11 Forecast maximum operational demand (sent out) in Queensland, Net Zero 2050 scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2021-22	9,666	9,205	2022	8,061	7,751
2025-26	9,932	9,436	2026	8,344	8,025
2030-31	10,563	10,071	2031	8,935	8,625
2040-41	14,088	13,515	2041	12,246	11,875

A2.3 Minimum demand outlook – Queensland

- Short term (0-5 years) – minimum operational demand is expected to start lower than in the 2020 ESOO due to increased forecasts for distributed PV generation at time of minimum demand.
- Medium to long term (5-30 years):
 - Minimum operational demand is expected to follow a downwards trend for the majority of the scenarios, due to increased distributed PV uptake overshadowing residential and business load growth.
 - Electrification results in the minimum operational demand in the Strong Electrification sensitivity diverging from the other scenarios, and is also why minimum operational demand rises sharply in the Net Zero 2050 scenario towards the end of the forecast horizon as major energy users, from the mining sector in particular, switch to electricity.
 - Negative minimum operational demand is forecast in the future for a few of the scenarios, presenting opportunities for market-based solutions to make use of excess supply at these times.

Figure 41 Forecast annual 50% POE minimum operational demand (sent-out) by scenario, Queensland



A2.4 Supply adequacy assessment – Queensland

Expected changes to existing and committed supply include:

- Between summer 2020-21 and 2021-22, 728 MW of additional VRE generation is expected to become available and 100 MW of large-scale battery storage is expected to be connected¹⁰⁹.
- The 34 MW Mackay Gas Turbine retired in April 2021, and the 420 MW Callide C unit 4 remains out of service and is not expected to return until late 2022.
- In February 2025, the 250 MW Kidston pumped hydro generator is assumed to connect.
- The 700 MW Callide B Power Station is scheduled to retire in 2028-29.

Figure 42 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on capacity during typical summer conditions.

Figure 43 shows forecast USE outcomes for Queensland under the three modelled scenarios¹¹⁰, highlighting that:

- In the Central and Slow Change scenarios, negligible USE is forecast in Queensland, with a minor increase on the retirement of Callide B. The temporary unavailability of one unit of Callide C is forecast to have minimal impacts on USE in 2021-22.
- In the Hydrogen Superpower scenario, expected USE remains low until 2026-27 and then increases significantly due to forecast electrification related and hydrogen industry related demand growth. In this scenario, it is assumed that additional supply would be developed to ensure the economic viability of hydrogen industries¹¹¹.

¹⁰⁹ Measured as summer typical capacity.

¹¹⁰ Both the Net Zero 2050 and Steady Progress scenarios are considered as the Central scenario.

¹¹¹ Expected USE in Hydrogen Superpower is indicative only. A soft energy target was used to model flexible components of electrolyser loads for hydrogen industries and a portion of this demand may not be met, beyond the expected USE reported. This further highlights the scale of the transition and the generation build required under this scenario.

Figure 42 Queensland assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31

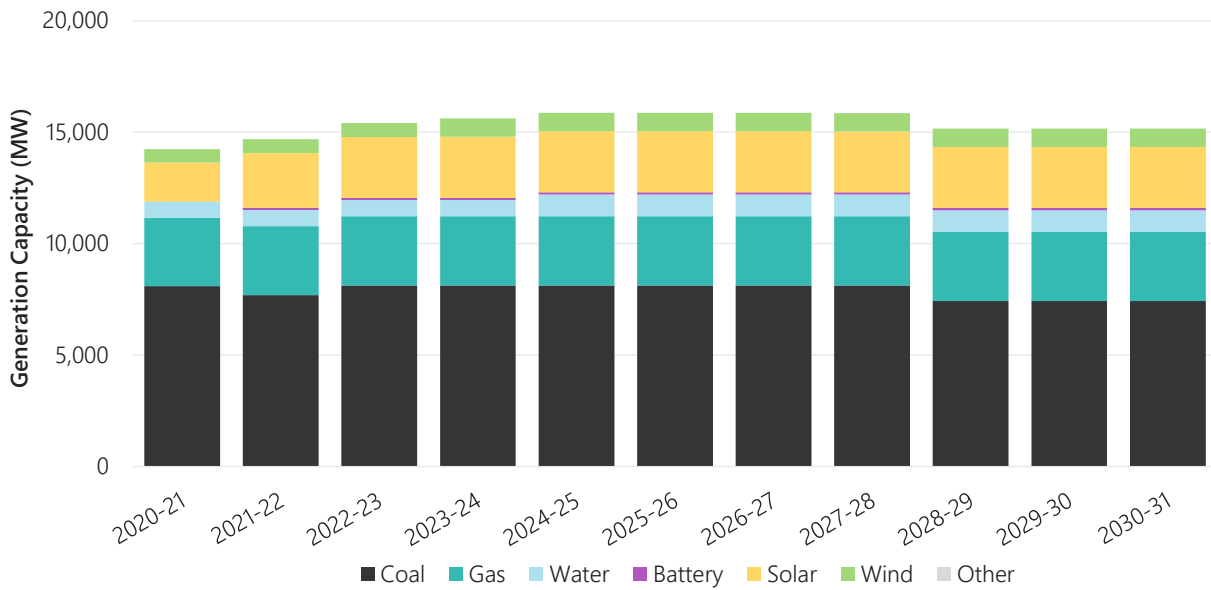
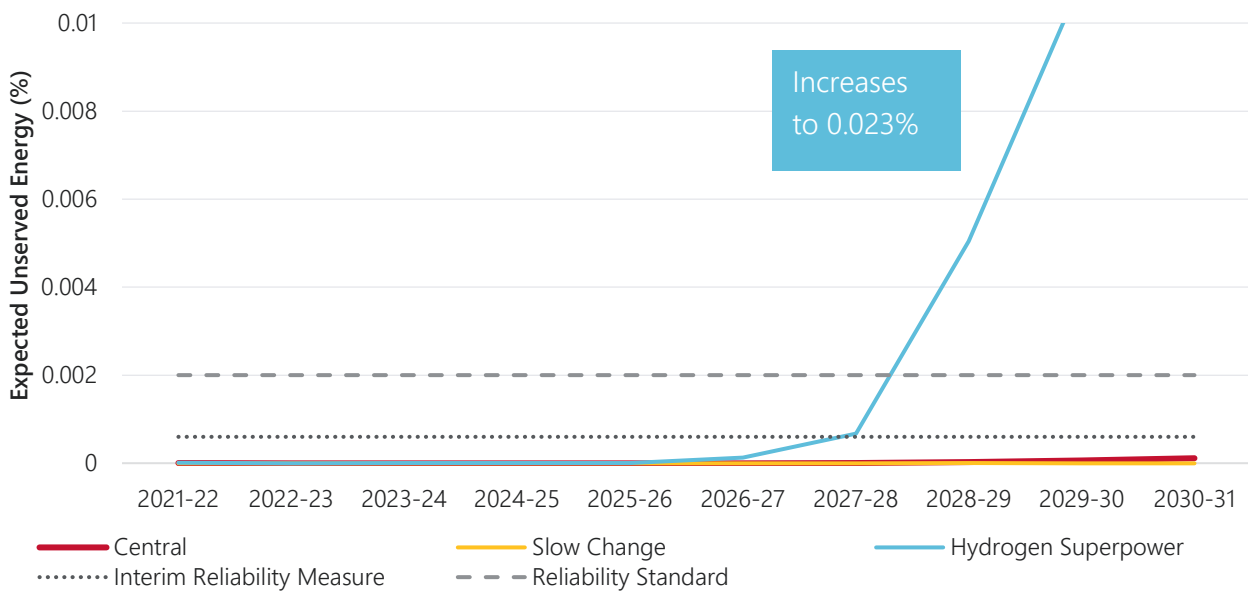


Figure 43 Queensland USE forecast by scenario



A2.5 Minimum operational demand assessment – Queensland

A2.5.1 System normal operation

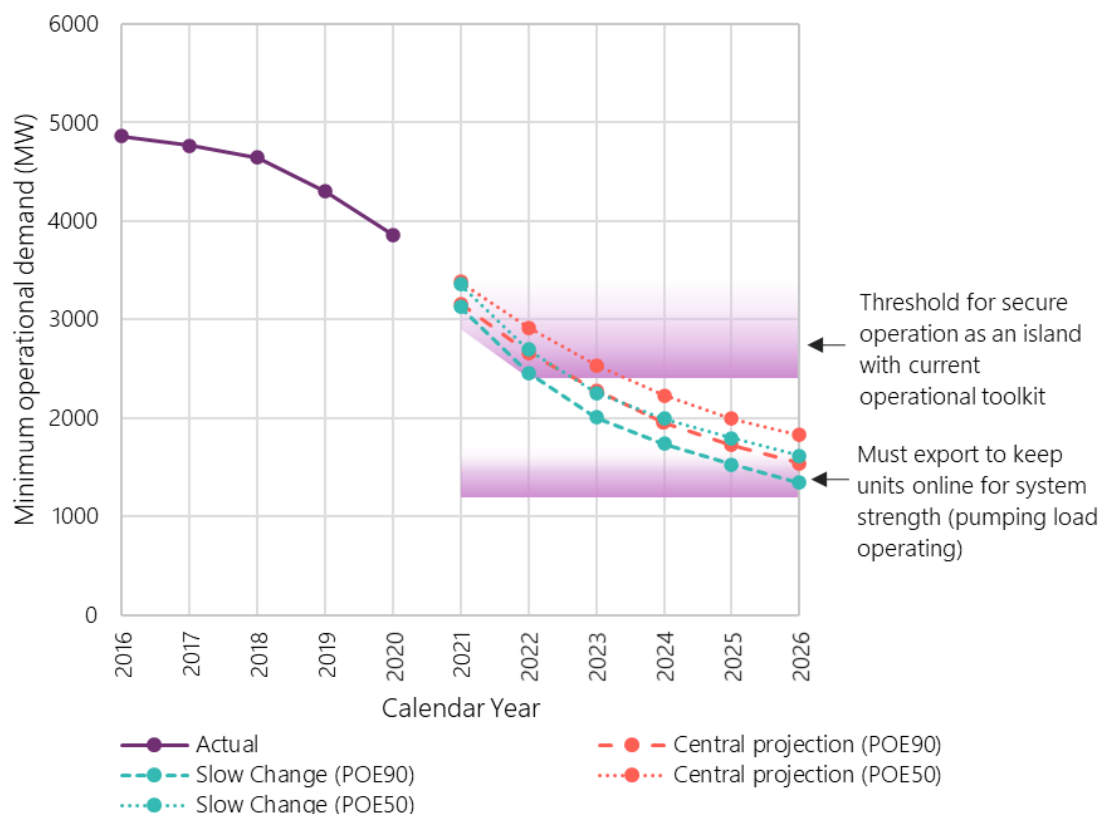
To maintain system strength in Queensland, various combinations of synchronous units in both North/Central Queensland and South Queensland must remain online during all system normal periods¹¹². Based on the present assets available in Queensland, a minimum of 1.5 GW to 2 GW of operational demand is required to

¹¹² System strength combinations for Northern Queensland are outlined in North Queensland System Strength Constraints, Powerlink https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/nqld-system-strength-constraints.pdf?la=en. South Queensland system strength combinations are determined by AEMO modelling. The Wivenhoe units have the ability to operate in synchronous condenser mode. This is currently not considered in the system strength combinations.

operate these units at their minimum loading levels. If typical pumping load is operating at Wivenhoe, this threshold reduces to 1.2 GW to 1.7 GW.

When operational demand falls below these levels, Queensland must export excess generation to other regions to maintain sufficient units online to deliver adequate system strength for system normal operation. This may not always be possible, if the Wivenhoe pumps or interconnectors are on outage, or limited due to other network or stability limits. As Figure 44 shows, minimum operational demand is expected to fall into this range in Queensland from 2025 in some scenarios.

Figure 44 Minimum operational demand thresholds in Queensland



A2.5.2 Operation of Queensland as an island

To operate Queensland as an island, in addition to maintaining sufficient units online to deliver the necessary levels of system strength, there must be sufficient assets operating to deliver the levels of frequency control required in the island.

This means there is an increased level of operational demand required, so the minimum units to deliver these services can be dispatched above their minimum generation levels, with sufficient footroom to deliver the necessary frequency lower services.

As shown in Figure 44, approximately 1.6 GW to 3.4 GW of operational demand is required to maintain the secure operation of Queensland as an island and deliver all the required services (based on the present assets

available in Queensland)¹¹³. The threshold decreases from 2021 to 2022 as battery projects are commissioned, because they provide additional frequency control services¹¹⁴. Commissioning of additional alternative assets that can provide these services at lower minimum generation levels (such as synchronous condensers, batteries, or other frequency control providers) will act to further decrease this threshold.

If Queensland is operating as an island and operational demand falls below these minimum operational demand thresholds, it will become increasingly difficult to provide the necessary levels of frequency control to meet the Frequency Operating Standards following credible contingencies.

Minimum operational demand is projected to start to fall into this range in 2021, indicating that operational flexibility at low demand times is already becoming challenging, if Queensland is operating as an island. During 2023 and 2024, in the Central projection, operational demand is forecast to fall below the lower parts of this threshold. This will mean shedding of whole consumer feeders in reverse flows may become necessary to securely operate a Queensland island, if a separation event occurred in a low demand period.

In the last 10 years, Queensland has separated from the rest of the NEM five times, or once every two years on average. Three of these separation events have occurred in the last three years, or once every year on average¹¹⁵.

The likelihood of Queensland separating from the NEM is much higher when Queensland is at credible risk of separation¹¹⁶. This usually occurs during planned or unplanned outages near the QNI, when Queensland is only one credible contingency away from operating as an island. In 2020-21, 53% of days (more than every second day) included a period where Queensland was at credible risk of separation. The vast majority of these periods stretched over the daily peak in distributed PV generation, mostly due to planned outages commencing and finishing at the start and end of the working day.

This was an increase compared with previous years, in which only 5-20% of days typically included a period where Queensland was at credible risk of separation. The increase in periods where Queensland is at credible risk of separation in 2020-21 was due to planned upgrades to the QNI as part of QNI Minor, a committed transmission project which is scheduled to be completed by June 2022. The incidence of Queensland operating at credible risk of separation will likely remain elevated until this project is completed.

¹¹³ This analysis assumes that the fast start units in Queensland are available as necessary; a higher level of demand will be required if this is not the case. The Terranora interconnector is assumed to be unavailable during Queensland island operation. If it is available, it may be possible to export up to 180 MW, although this may be reduced due to network and other stability limits. This analysis assumes that one pump at Wivenhoe is operational. This analysis assumes that all non-essential units are curtailed and incorporates a 'return-to-secure' buffer. This buffer ensures that in the event the largest load trips and does not return within 30 minutes, there will be sufficient post-contingency lower FCAS services to operate a secure system. The 'return-to-secure' buffer is equal to the size of the largest post-contingency load. This analysis assumes full BESS FCAS availability and adds 110 MW to the thresholds to meet lower regulation FCAS requirements.

¹¹⁴ This analysis assumes the commissioning of the Wandoan South BESS in 2022 and is assumed to provide Fast Frequency Response.

¹¹⁵ In the last 10 years, Queensland has separated from the NEM on 13 November 2011, 22 May 2014, 25 August 2018, 7 January 2020, and 25 June 2021.

¹¹⁶ While Queensland is at credible risk of separation, interregional transfer limits between Queensland and New South Wales are significantly reduced (from around 1,000 MW to approximately 200-300 MW). In addition, sufficient lower FCAS to cover the loss of QNI flows to New South Wales must be enabled in Queensland, which usually requires generating units to be dispatched above their minimum generation levels. In this scenario, if demand falls below the aggregate minimum generating levels for units required for system strength and FCAS, Queensland's ability to export the difference may be limited, and QNI flows may exceed secure limits.

A3. South Australia outlook

The following sections present:

- Consumption, maximum demand, and minimum demand outlooks for South Australia for all scenarios out to 2050-51.
- Supply adequacy assessments for South Australia over the next 10 years for the Slow Change, Central and Hydrogen Superpower scenarios, in the absence of any further supply developments.
- An assessment of when operational minimum demand will reach thresholds for secure operation of the power system in South Australia.

A3.1 Annual consumption outlook – South Australia

Figure 45 shows the component forecasts for operational consumption in South Australia under the Net Zero 2050 scenario.

Both the Net Zero 2050 and Steady Progress scenarios were selected as the Central demand scenarios for the supply adequacy assessments in this ESOO. Figure 45 shows the Net Zero 2050 scenario forecast to 2050-51, as this scenario provides insight into the potential consumption impacts of industrial electrification associated with an economy-wide decarbonisation Net Zero emissions objective by 2050, and is therefore informative for stakeholders that have aspirational or legislated goals to achieve this objective.

The figure shows that in the Net Zero 2050 scenario, AEMO forecasts:

- 2021-22 to 2030-31 (1-10 years) – continued strong growth of distributed PV and a lower than previously forecast for the business mass market sector, with relative stability throughout the 10-year horizon for business mass market and large industrial load consumption.
- 2031-32 to 2040-41 (11-20 years) – consumption growing strongly due to electrification growth from the transport, business and residential sectors, despite continuing growth in distributed PV and energy efficiency offsetting increases in business mass market and residential delivered energy.
- 2041-42 to 2050-51 (21-30 years) – similar growth trends continuing from the preceding decade, with a step up of electrification in the business sector from the mid-2040s, and strongly growing consumption as hydrogen production for domestic usage emerges, offsetting lower industrial loads from the late 2040s.

Figure 46 shows forecasts across the scenarios, highlighting that:

- Electrification dominates the growth trajectories of both the **Strong Electrification** sensitivity and **Hydrogen Superpower** scenario, with only domestic production of hydrogen shown in the latter.
- **Slow Change**, with short-term rapid distributed PV growth and no electrification, has the lowest projected growth throughout the forecast horizon.
- **Step Change** is higher than Net Zero 2050 in the short term, from a higher electrification forecast, but is eclipsed from 2035 as electrification in Net Zero 2050 ramps up, and the distributed PV forecast in Step Change is higher and sustained.
- **Steady Progress**, while tracking closely to Net Zero 2050 in the first 10 years, has limited long-term electrification impacts, so consumption is forecast to be about 13 TWh lower than Net Zero 2050 by 2050-51.

Note that Figure 46 does not include consumption related to hydrogen export and green steel production, because the regional allocation of hydrogen exports will be an outcome of the long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 45 South Australia electricity consumption, actual and forecast, 2013-14 to 2050-51, Net Zero scenario

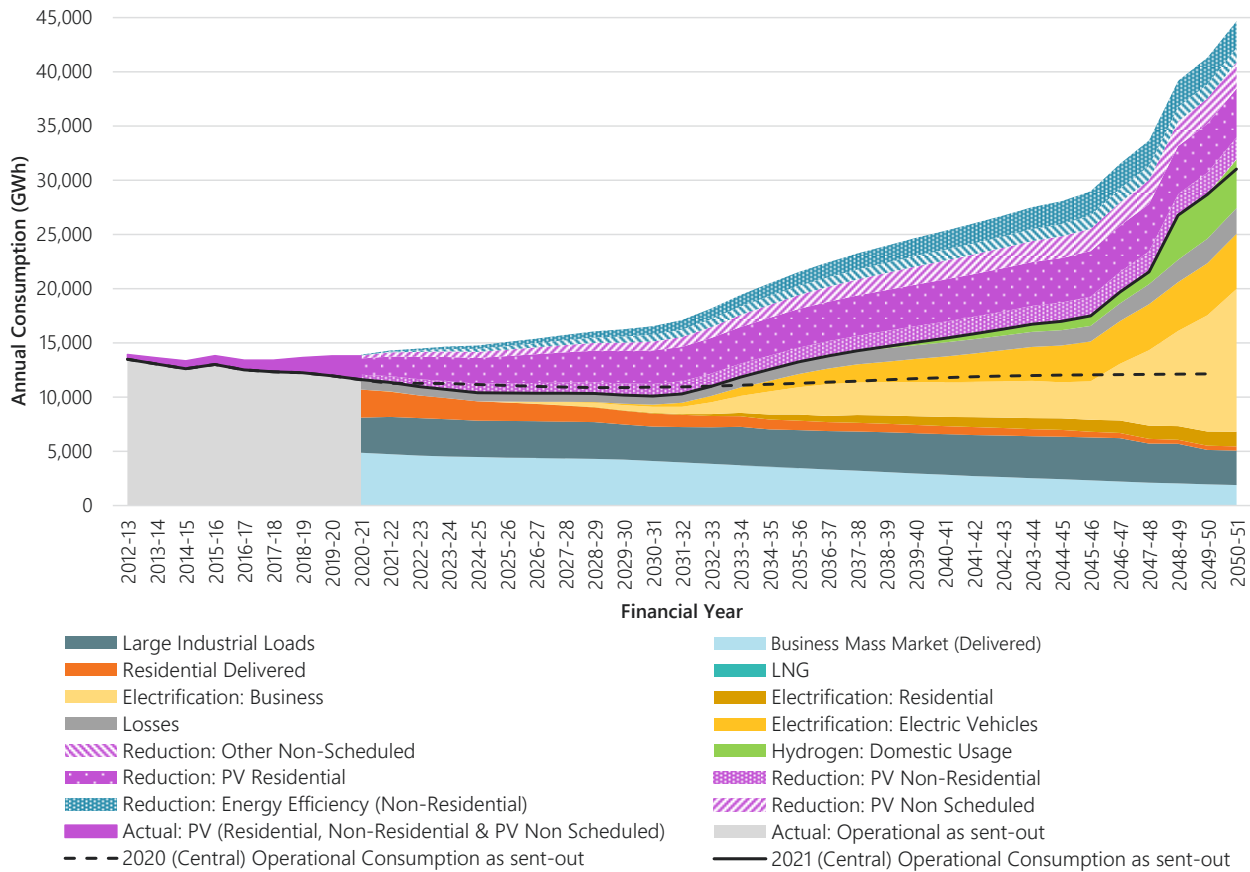
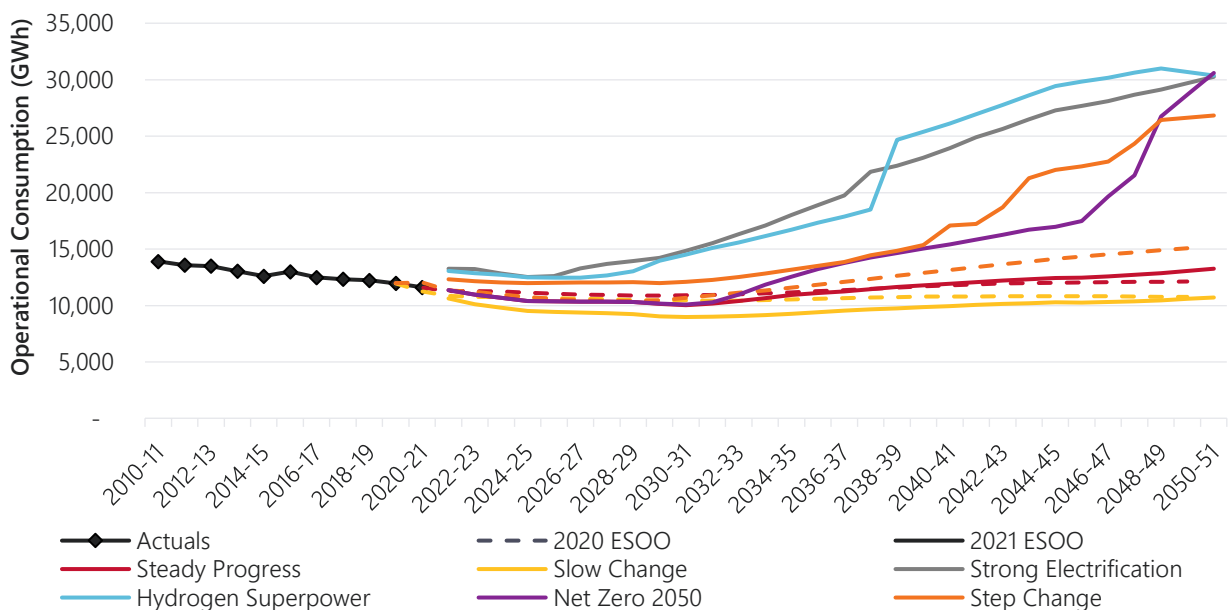


Figure 46 South Australia operational consumption in GWh, actual and forecast, 2010-11 to 2050-51, all scenarios



A3.2 Maximum demand outlook – South Australia

- Short term (0-5 years) – maximum operational demand is expected to be consistent with the 2020 ESOO, as the influence of higher distributed PV uptake on maximum operational demand reduces and high demand periods are experienced in the early evening. Minimal changes in maximum operational demand are expected, as influencing drivers such as electrification and EV uptake do not act to materially increase maximum demand during this period.
- Medium to long term (5-30 years):
 - Maximum operational demand is expected to increase across all scenarios, largely driven by increased EV uptake and electrification. By 2040-41 it is expected that EVs and electrification will contribute around 20% of one-in-two year maximum operational demand in the Net Zero 2050 scenario, with the majority of EVs still following a convenience charging profile.
 - The Slow Change and Steady Progress scenarios assume a modest increase in electrification, resulting in these forecasts aligning more closely to the ESOO 2020 Central scenario.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below; these will be presented in future versions of the demand forecasts as an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 47 Forecast summer 10% POE maximum operational demand (sent-out) by scenario, South Australia

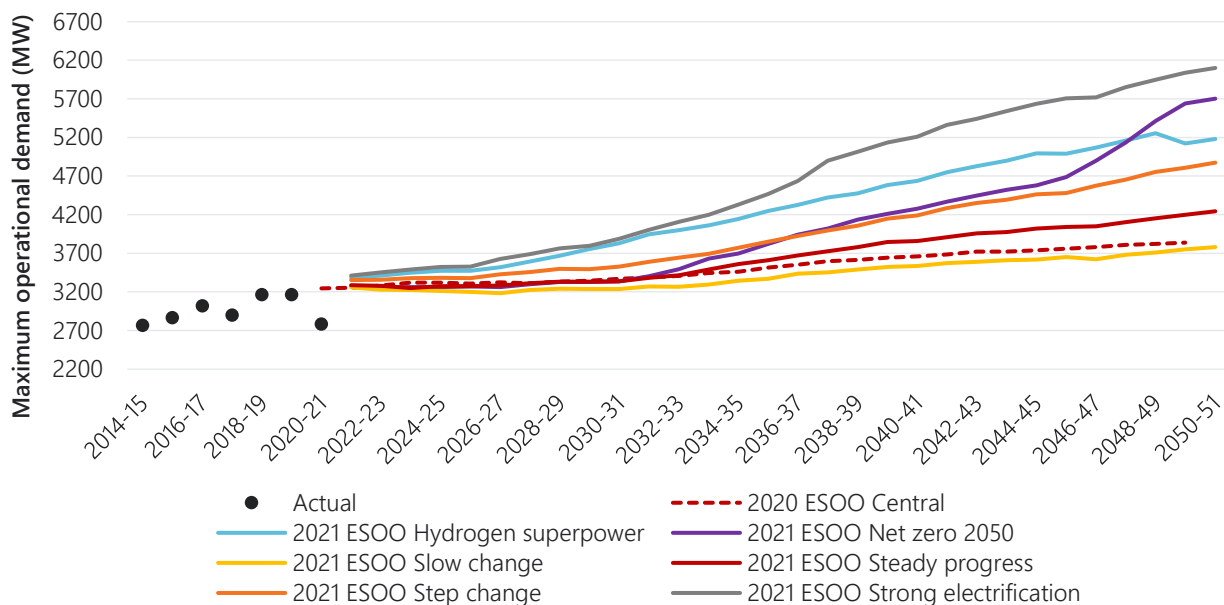


Table 12 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Net Zero 2050 scenario. Maximum operational demand in South Australia is forecast to keep occurring in summer over the forecast horizon.

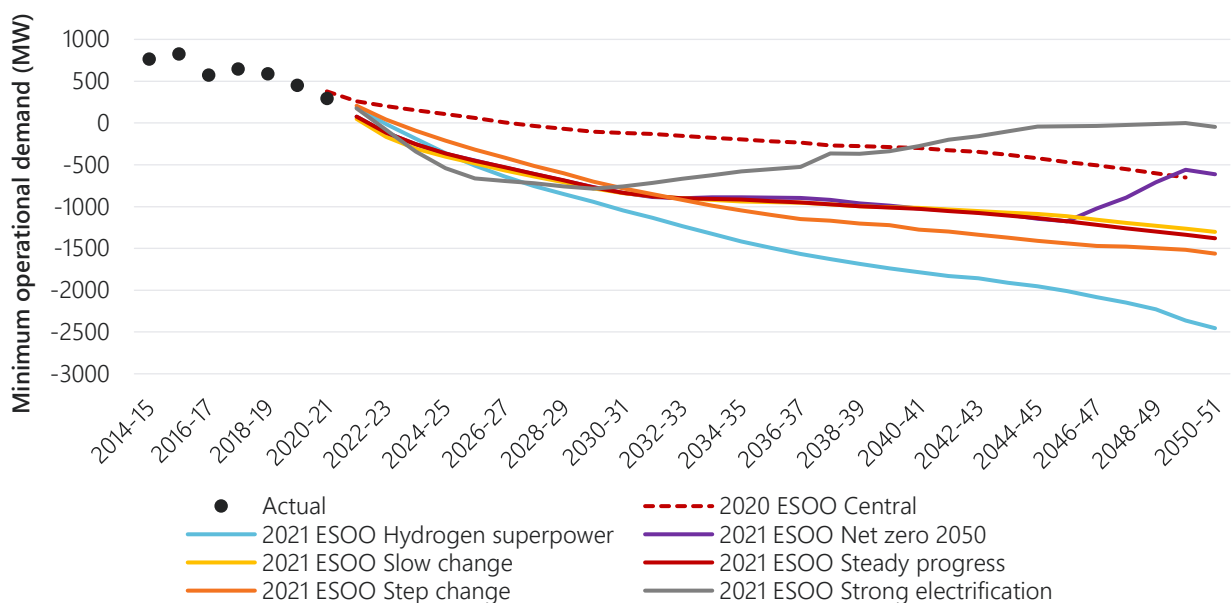
Table 12 Forecast maximum operational demand (sent out) in South Australia, Net Zero 2050 scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2021-22	3,277	2,886	2022	2,556	2,466
2025-26	3,269	2,871	2026	2,588	2,504
2030-31	3,337	2,956	2031	2,739	2,637
2040-41	4,278	3,862	2041	3,839	3,719

A3.3 Minimum demand outlook – South Australia

- Short term (0-5 years) – minimum operational demand is expected to continue to decline in the short term across all scenarios primarily driven by the uptake of distributed PV. Negative 50% POE minimum operational demand events are expected as early as 2022-23, earlier than anticipated in the 2020 ESOO.
- Medium to long term (5-30 years):
 - The decline in minimum operational demand is expected to be dampened by the increased uptake in EVs, batteries, and electrification.
 - Negative minimum operational demand is expected across all scenarios for most of the forecast horizon.
 - From 2045-46, increased electrification is forecast to increase minimum operational demand in the Net Zero 2050 scenario.
 - The Strong Electrification sensitivity and the Net Zero 2050 scenario both diverge from the downward trend in minimum operational demand at different time periods along the forecast horizon, largely driven by increased electrification.

Figure 48 Forecast annual 50% POE minimum operational demand (sent-out) by scenario, South Australia



A3.4 Supply adequacy assessment – South Australia

- Between summer 2020-21 and 2021-22, 127 MW of additional VRE generation is expected to become available, as measured in summer typical capacity.
- The 120 MW Torrens Island A Unit 1 is scheduled to retire completely before the coming summer, with the 120 MW Torrens Island A Unit 3 mothballed until it is scheduled to retire late 2022.
- One Torrens Island B unit (200 MW) is mothballed from 2021-22 to 2023-24 inclusive.
- The 180 MW Osborne gas generator is scheduled for retirement in December 2023, followed by the modelled connection of 154 MW Snapper Point Power Station (previously Temporary Generation North) in 2023-24¹¹⁷.
- Several generators are expected to be retired in 2030-31, including the 156 MW Dry Creek Power Station, 90 MW Mintaro Power Station, 74 MW Port Lincoln Power Station, 63 MW Snuggery Gas Station, and 30 MW Dalrymple BESS.

Figure 49 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on capacity during typical summer conditions.

Figure 49 South Australia assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31

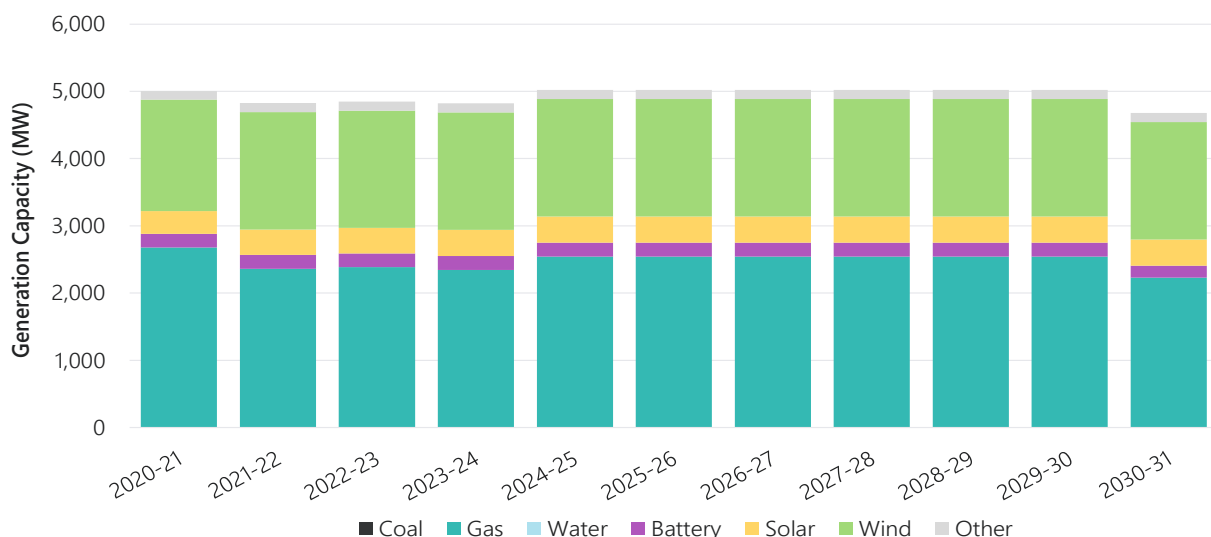
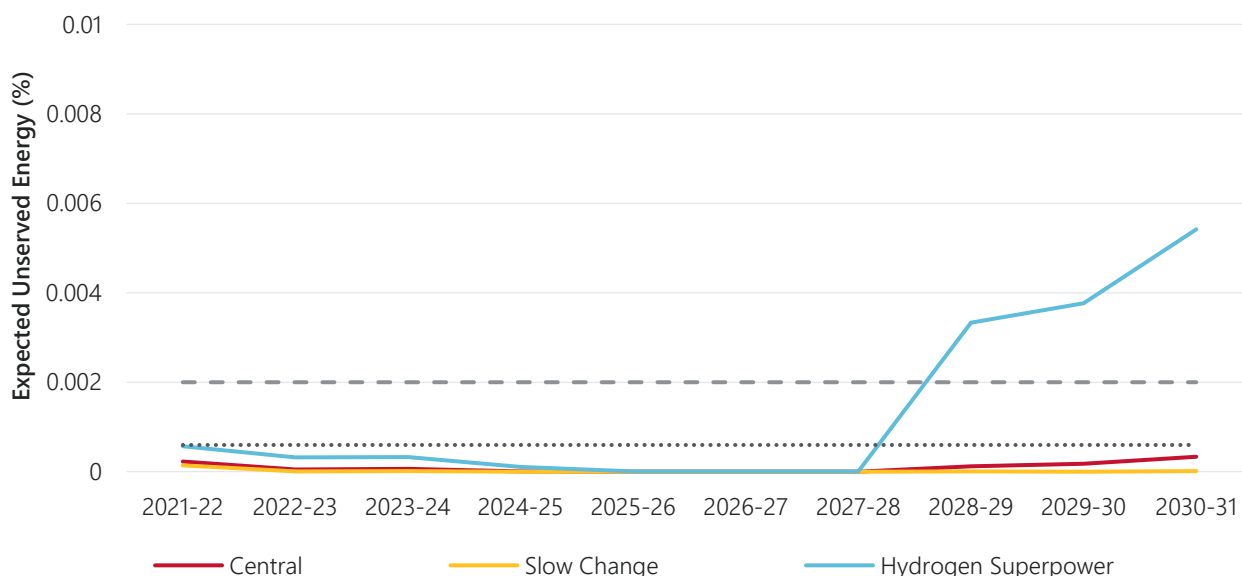


Figure 50 shows forecast expected USE outcomes for South Australia under the three modelled scenarios:

- In both the Central and Slow Change scenarios, expected USE is forecast to be below both the reliability standard and the IRM during the 2021 ESOO modelling horizon.
- Expected USE is above the reliability standard from 2028-29 under the Hydrogen Superpower scenario. Under this scenario it is assumed that additional supply developments would take place to ensure economic viability of hydrogen industries and other increased consumer and industrial needs.

¹¹⁷ The Snapper Point Power Station provided scheduled capacities indicating it would be available during summer 2021-22. As this project is classified as Committed*, this ESOO assumes a full commercial use date of 1 July 2023.

Figure 50 South Australia USE forecast by scenario



A3.5 Minimum operational demand assessment – South Australia

South Australia reached a minimum operational demand record of 300 MW on 11 October 2020.

Given rapid growth in distributed PV during 2020 and 2021, AEMO projects that under certain scenarios, South Australia could reach zero or negative demand as early as spring 2021. This means the entire underlying demand in South Australia will be met by distributed resources in certain time periods. AEMO understands this to be a world first for a gigawatt-scale power system.

Minimum operational demand is projected to continue to decline beyond this point, reaching -310 MW by 2024 and -540 MW by 2026 in the Central scenario, or as low as -360 MW by 2024 in the Slow Change scenario. Excess generation will be exported to other regions over interconnectors, where possible.

Since 28 September 2020, all new DER installations in South Australia must have the ability to be remotely curtailed, when necessary, as an emergency last resort to maintain power system security¹¹⁸. This provides the necessary backstop tool, the CSML Mechanism, to maintain power system security.

Development of appropriate market and regulatory arrangements is required to minimise the need to utilise PV curtailment, so it remains a rare event, only deployed under exceptional and unusual circumstances.

SA Power Networks (SAPN) is pursuing the implementation of a “Flexible Exports” mechanism¹¹⁹ to deliver the necessary long-term technical capabilities.

Under present operating procedures, AEMO instructs ElectraNet to instruct SAPN to maintain demand above 600 MW if South Australia is operating as an island, or above 400 MW if South Australia is operating at credible risk of separation due to a network outage in the Victorian network. In 2020, South Australian operational demand was below 600 MW for 2% of the time; this is forecast to increase to 8% of the time in 2022 and 12% of the time in 2023. The proportion of time operational demand was below 400 MW was 0.04% in 2020, forecast to increase to 4% of the time in 2022 and 7% of the time in 2023. These thresholds

¹¹⁸ Government of South Australia, Department for Energy and Mining, at https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes/remote_disconnect_and_reconnection_of_electricity_generating_plants.

¹¹⁹ SA Power Networks, Flexible Exports, at <https://www.sapowernetworks.com.au/industry/flexible-exports/>.

are only applicable when South Australia is at credible risk of islanding or islanded, and the thresholds may be higher under some circumstances¹²⁰.

These thresholds have been determined based on power system studies that account for the behaviour of distributed PV during power system disturbances, and are intended to maintain the power system in a secure technical operating envelope.

It is becoming increasingly challenging to allow network outages to proceed if they result in a credible risk of separation of South Australia from the rest of the NEM. Network outages are often required for commissioning of new generating units or network assets. This highlights a growing need for new market frameworks in South Australia that encourage consumers to participate in the market (see Chapter 6).

AEMO continues to refine its models and procedures, aiming to increase robustness and make operating arrangements more dynamic to minimise unnecessary PV curtailment.

The thresholds will also be continually refined in light of the many changes occurring in the South Australian power system, including commissioning of the ElectraNet synchronous condensers and installation of further BESS offering fast frequency response.

¹²⁰ For example, if there are network outages in the South Australian network which put South Australia at credible risk of separation, or if the unintended disconnection of distributed PV in response to a credible fault could increase contingency sizes and lead to a security risk that cannot be managed via other means.

A4. Tasmania outlook

The following sections present:

- Consumption, maximum demand, and minimum demand outlooks for Tasmania for all scenarios out to 2050-51.
- Supply adequacy assessments for Tasmania over the next 10 years for the Slow Change, Central, and Hydrogen Superpower scenarios, in the absence of any further supply developments.
- An assessment of when operational minimum demand will reach thresholds for secure operation of the power system in Tasmania.

A4.1 Annual consumption outlook –Tasmania

Figure 51 shows the component forecasts for operational consumption in Tasmania under the Net Zero 2050 scenario.

Both the Net Zero 2050 and Steady Progress scenarios were selected as the Central demand scenarios for the supply adequacy assessments in this ESOO. Figure 51 shows the Net Zero 2050 scenario forecast to 2050-51, as this scenario provides insight into the potential consumption impacts of industrial electrification associated with an economy-wide decarbonisation Net Zero emissions objective by 2050, and is therefore informative for stakeholders that have aspirational or legislated goals to achieve this objective.

In the Net Zero 2050 scenario, AEMO forecasts:

- 2021-22 to 2030-31 (1-10 years) – moderate growth in large industrial loads and residential load.
- 2031-32 to 2040-41 (11-20 years) – electrification growth from the transport and business sectors strongly growing consumption, partially countered by reductions in usage due to energy efficiency savings, particularly in the manufacturing/mining components of the large industrial loads.
- 2041-42 to 2050-51 (21-30 years) – similar growth trends continuing from the preceding decade, with strong consumption growth driven by a step up of electrification in the business sector and the emergence of hydrogen production for domestic usage from the mid-2040s, partially offset by further reductions in large industrial loads from the late 2040s.

Figure 52 shows forecasts across the scenarios, highlighting that:

- Electrification dominates the growth trajectories of both the **Strong Electrification** sensitivity and **Hydrogen Superpower** scenario.
- **Slow Change** considers the downside risks from large load closures, although the risk has slightly reduced compared to the 2020 ESOO forecast. This risk and the absence of electrification sees the lowest projected consumption of the scenarios throughout the forecast horizon.
- **Step Change** has a higher short-term forecast than Net Zero 2050, due to larger electrification forecasts, and a slightly lower long-term trajectory than Net Zero 2050 due to a higher PV forecast and lower electrification from 2030 onwards.
- **Steady Progress**, while tracking closely to Net Zero 2050 in the first 10 years, has limited long-term electrification impacts and consumption is about 1 TWh lower than Net Zero 2050 by 2050-51.

Note that Figure 52 does not include consumption related to hydrogen export and green steel production, because the regional allocation of hydrogen exports will be an outcome of the long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 51 Tasmania electricity consumption, actual and forecast, 2013-14 to 2050-51, Net Zero scenario

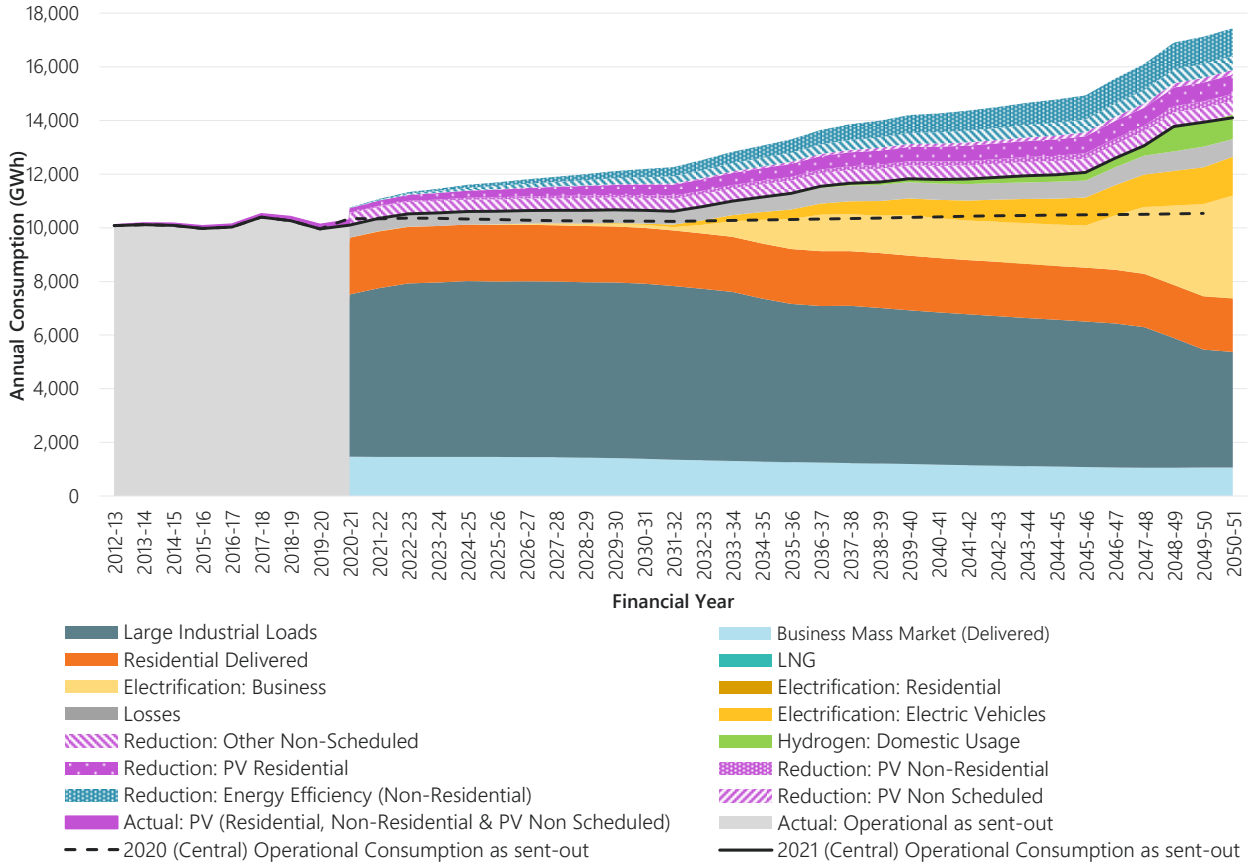
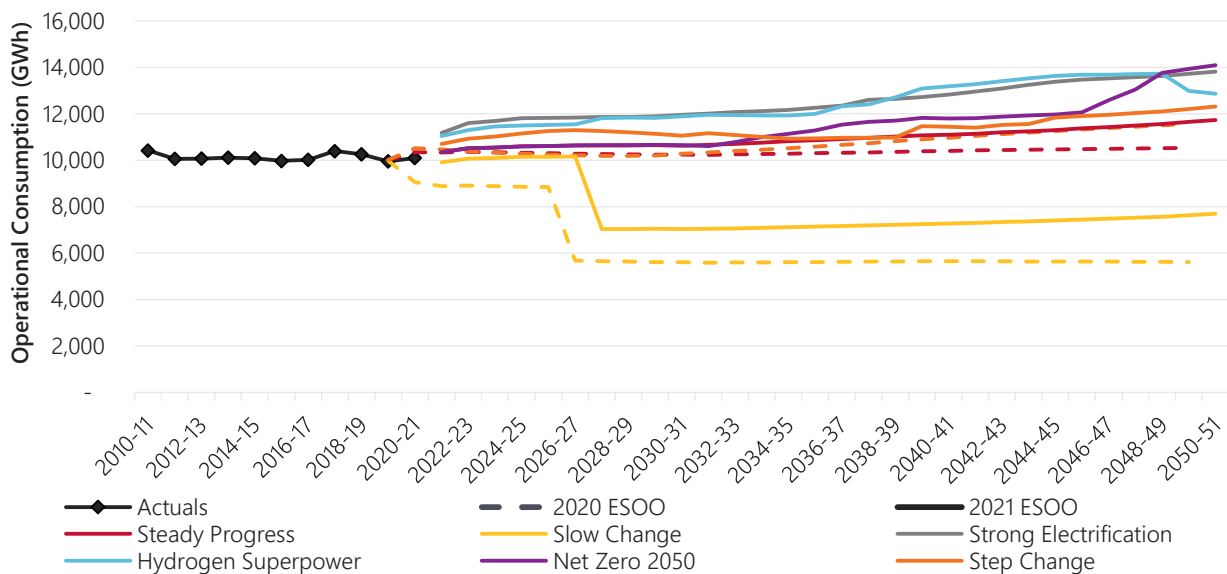


Figure 52 Tasmania operational consumption in GWh, actual and forecast, 2010-11 to 2050-51, all scenarios



A4.2 Maximum demand outlook – Tasmania

- Short term (0-5 years) – maximum operational demand in Tasmania is largely driven by heating load from the residential sector. Slight increases in maximum demand in the short term are expected to be driven by increased residential consumption.
- Medium to long term (5-30 years):
 - Maximum operational demand in Tasmania is expected to increase from 2030-31 onwards, due to increased EV uptake and electrification.
 - EVs are expected to contribute to around 6% of one-in-two year maximum operational demand by 2040-41 in the Net Zero 2050 scenario¹²¹, the lowest proportion amongst the NEM regions due to the relatively high proportion of industrial load in Tasmania.
 - The Slow change scenario captures the risks of large industrial load closures, causing a large drop in the maximum operational demand forecast in the late 2020s.
 - The other scenarios forecast higher maximum operational demand than in the 2020 ESOO; variance between the scenarios is a product of underlying assumptions, primarily the impact of electrification.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below; these will be presented in future versions of the demand forecasts as an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 53 Forecast winter 10% POE maximum operational demand (sent-out) by scenario, Tasmania

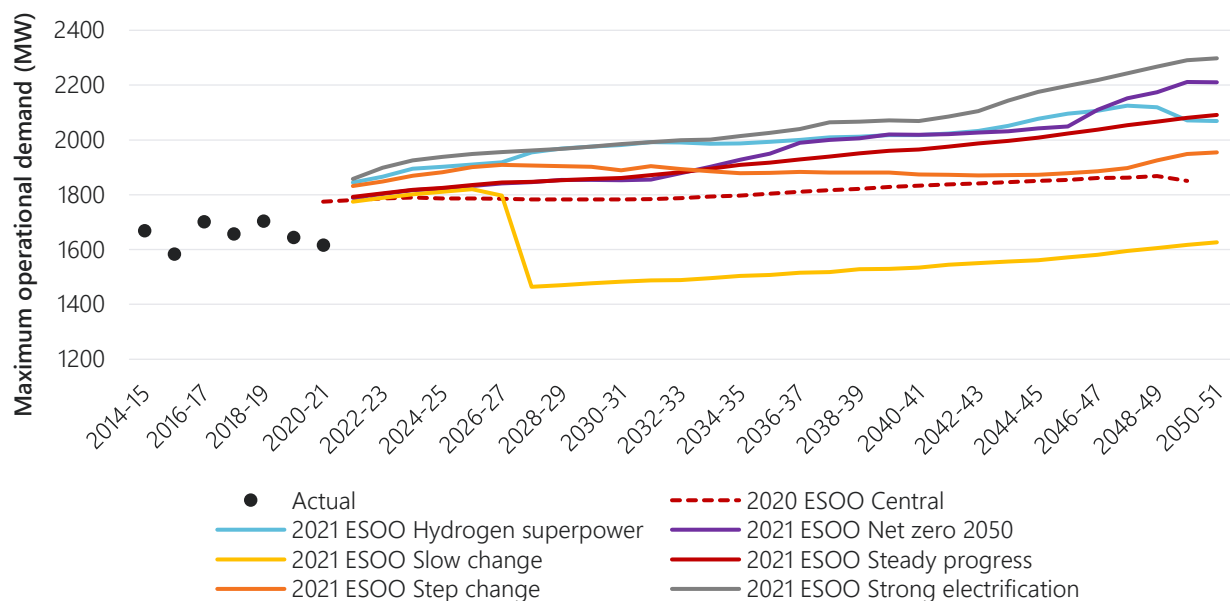


Table 13 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Net Zero 2050 scenario. Maximum operational demand in Tasmania is forecast to continue occurring in winter.

¹²¹ Assumes the majority of EVs follow a convenience charging profile.

Table 13 Forecast maximum operational demand (sent out) in Tasmania, Net Zero 2050 scenario (MW)

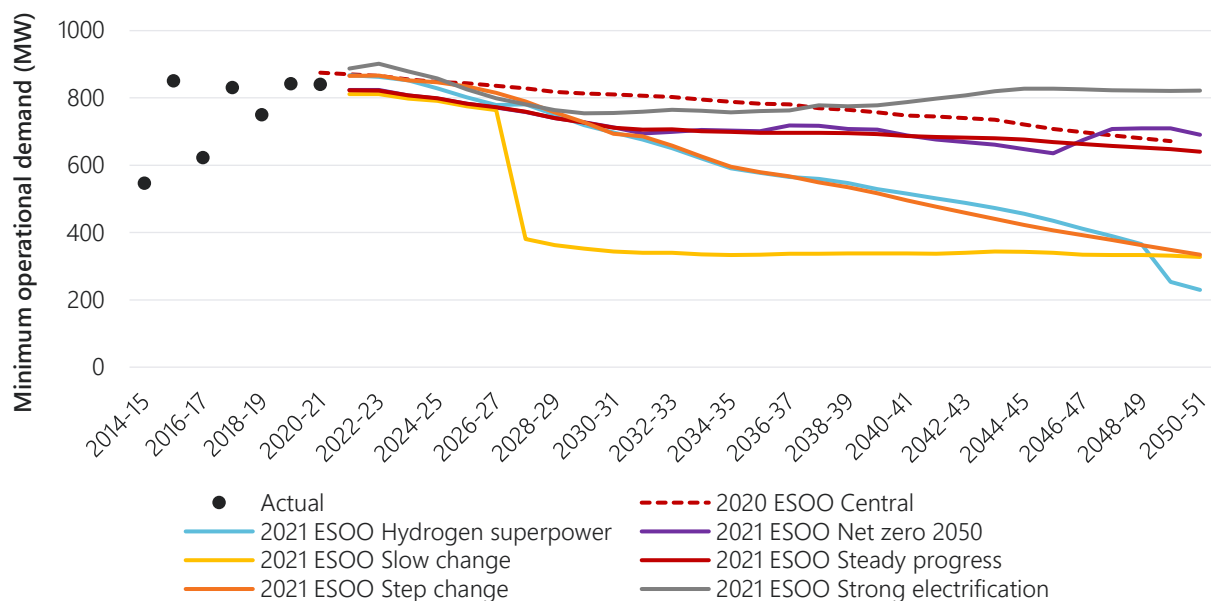
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2021-22	1,400	1,365	2022	1,789	1,749
2025-26	1,437	1,407	2026	1,832	1,793
2030-31	1,450	1,422	2031	1,853	1,814
2040-41	1,582	1,552	2041	2,018	1,975

Historically, maximum operational demand events have happened in Tasmania before or after business hours, driven by residential heating load and large industrial loads. Over the forecast horizon, AEMO is forecasting a move away from morning maximum demand events, to a majority of evening maximum demand events.

A4.3 Minimum demand outlook – Tasmania

- Short term (0-5 years) – minimum operational demand is expected to remain relatively stable in the short term, following a similar trajectory to the 2020 ESOO Central scenario. This trend is expected to continue until the influence of distributed PV uptake and electrification increases.
- Medium to long term (5-30 years):
 - Minimum operational demand is expected to follow a downwards trend in all scenarios (except the Strong Electrification sensitivity and the Slow Change scenario) driven by high distributed PV uptake growth.
 - The Slow Change scenario forecasts a large drop in minimum operational demand in the late 2020s, taking into consideration the risks of large industrial load closures.
 - Increased electrification assumed in the Strong Electrification sensitivity and (towards the end of the outlook period) in the Net Zero 2050 scenario curbs the downwards trend in minimum operational demand seen in the other scenarios.

Figure 54 Forecast summer 50% POE minimum operational demand (sent-out) by scenario, Tasmania



A4.4 Supply adequacy assessment –Tasmania

There are currently no committed projects expected to commence commercial operations in Tasmania during the 2021 ESOO modelling horizon.

Figure 55 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on capacity during typical summer conditions.

Figure 56 shows forecast USE outcomes for Tasmania under the three modelled scenarios. In the 2021 ESOO, both the Net Zero 2050 and Steady Progress scenarios are considered as the Central.

Figure 55 Tasmania assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31

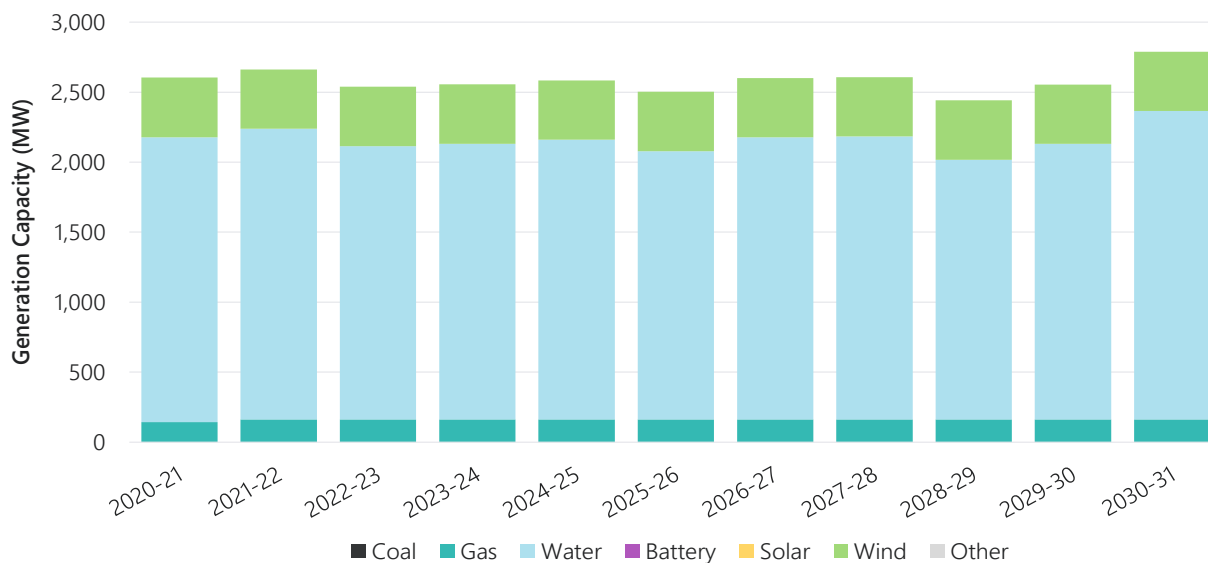
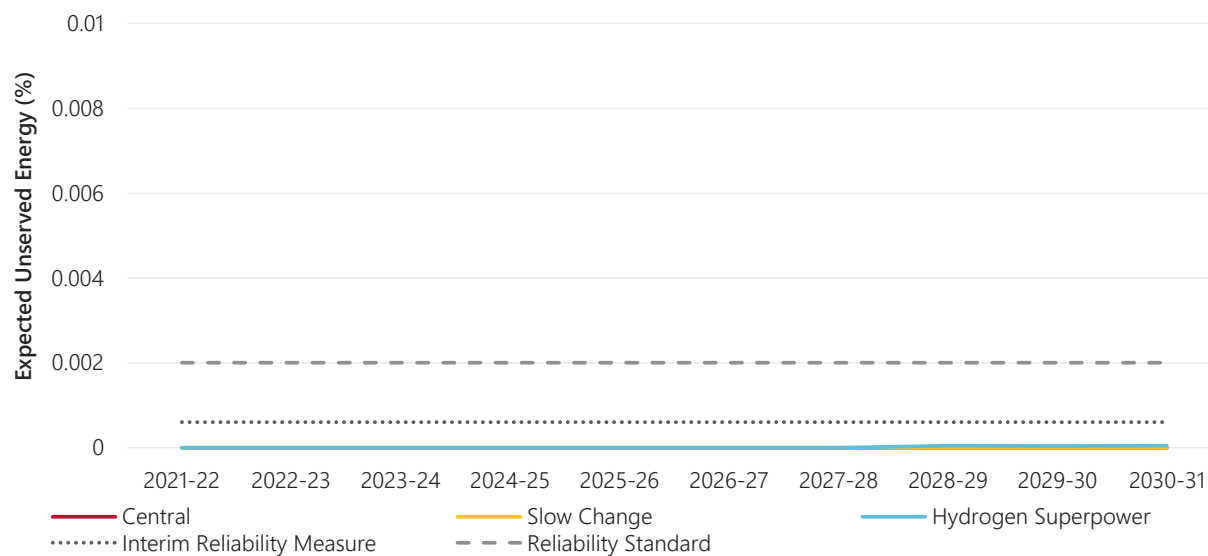


Figure 56 Tasmania USE forecast by scenario



The 2021 ESOO projects no USE in Central and Slow Change scenarios. In the Hydrogen Superpower scenario, no expected USE is forecast until 2027-28, when a small level of USE is expected¹²².

Tasmania is forecast to have adequate generation capacity, despite supply being limited at times due to reservoir storage levels. The resilience of the Tasmania electricity supply to rainfall conditions is further detailed in AEMO's Energy Adequacy Assessment Projection¹²³.

¹²² Expected USE in Hydrogen Superpower is indicative only. A soft energy target was used to model electrolyser loads for export-related hydrogen demand and a portion of this demand may not be met, beyond the expected USE reported. This further highlights the scale of the transition and the generation build required under this scenario.

¹²³ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/energy-adequacy-assessment-projection-eaap>.

A5. Victoria outlook

The following sections present:

- Consumption, maximum demand, and minimum demand outlooks for Victoria for all scenarios out to 2050-51.
- Supply adequacy assessments for Victoria over the next 10 years for the Slow Change, Central, and Hydrogen Superpower scenarios, in the absence of any further supply developments.
- An assessment of when operational minimum demand will reach thresholds for secure operation of the power system in Victoria.

A5.1 Annual consumption outlook – Victoria

Figure 57 shows the component forecasts for operational consumption in Victoria under the Net Zero 2050 scenario.

Both the Net Zero 2050 and Steady Progress scenarios were selected as the Central demand scenarios for the supply adequacy assessments in this ESOO. Figure 57 shows the Net Zero 2050 scenario forecast to 2050-51, as this scenario provides insight into the potential consumption impacts of industrial electrification associated with an economy-wide decarbonisation Net Zero emissions objective by 2050, and is therefore informative for stakeholders that have aspirational or legislated goals to achieve this objective.

In the Net Zero 2050 scenario, AEMO forecasts:

- 2021-22 to 2030-31 (1-10 years) – continued growth in distributed PV, energy efficiency, and a moderate reduction in business mass market load drive short-term reductions in energy.
- 2031-32 to 2040-41 (11-20 years) – electrification growth from the transport, residential (in particular gas heating), and business sectors drives strong consumption growth, although it is slightly moderated by growth in distributed PV.
- 2041-42 to 2050-51 (21-30 years) – consumption growing strongly, due to electrification growth from the transport, residential, and business sectors, partially offset by modest growth in business energy efficiency and distributed PV. A step up of electrification in the business and residential sectors grows consumption further from the mid-2040s. Unlike the other regions, hydrogen production in the mid-2040s is forecast to be primarily from steam methane reformation and is not forecast to affect electricity demand¹²⁴.

Figure 58 shows forecasts across the scenarios, highlighting that:

- Electrification dominates the growth trajectories of both the **Strong Electrification** sensitivity and **Hydrogen Superpower** scenario, with only domestic hydrogen production shown in the latter.
- **Slow Change** contains the lowest consumption forecast due to early large industrial load closure risks, short-term strong distributed PV growth, and no electrification.
- **Step Change** has higher electrification impacts in the short term compared to Net Zero 2050, resulting in a higher sustained forecast for much of the forecast horizon despite stronger distributed PV forecasts.

¹²⁴ For more, see the 2021 IASR, Section 3.3.14, at <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf>.

- **Steady Progress**, while tracking closely to Net Zero 2050 in the first 10 years, has limited long-term electrification impacts and forecast consumption is about 30 TWh lower than Net Zero 2050 by 2050-51.

Figure 58 does not include consumption related to hydrogen export and green steel production, because the regional allocation of hydrogen exports will be an outcome of the long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 57 Victoria electricity consumption, actual and forecast, 2013-14 to 2050-51, Net Zero scenario

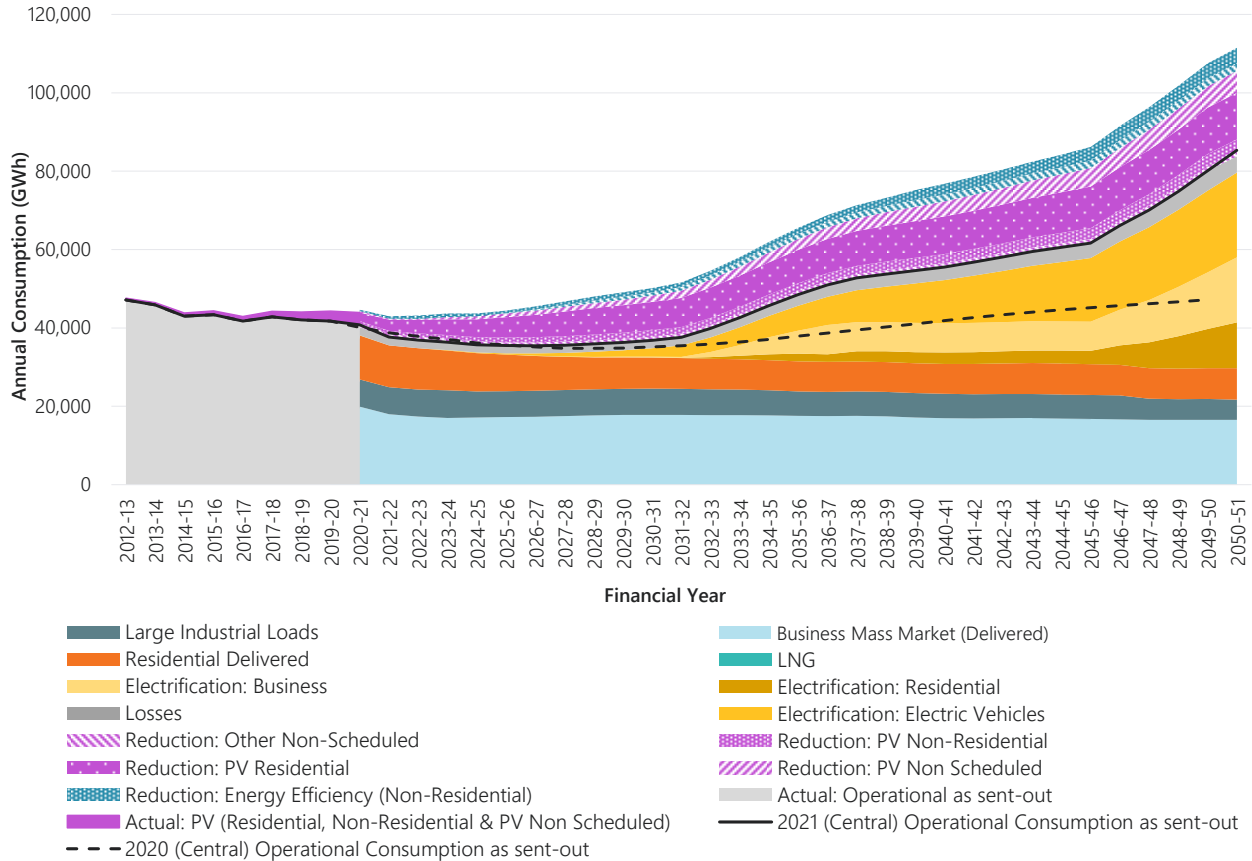
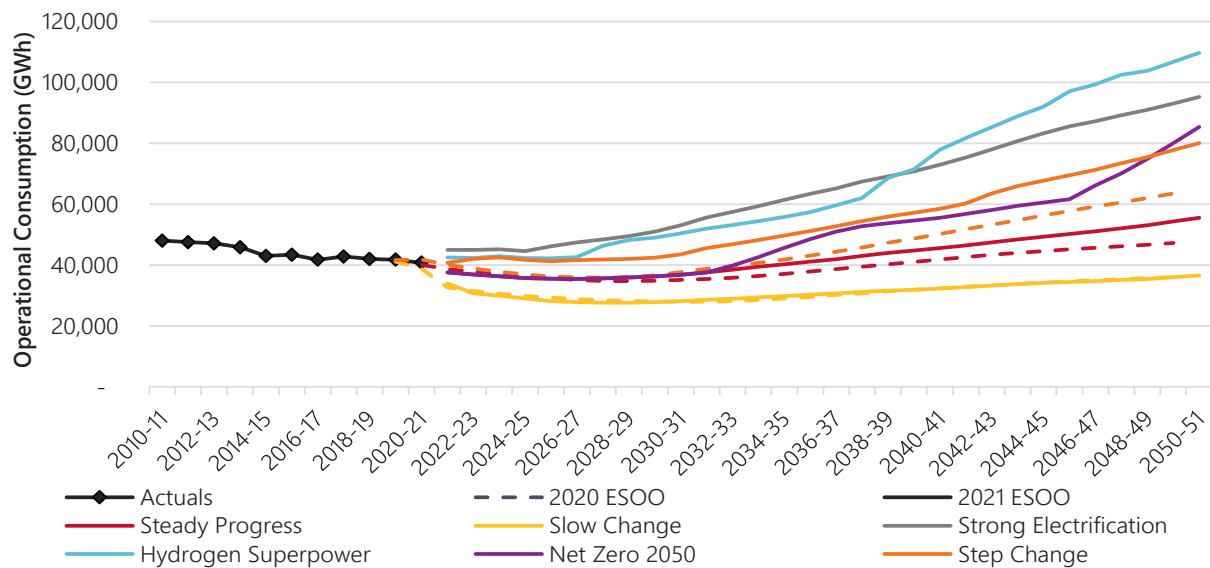


Figure 58 Victoria operational consumption in GWh, actual and forecast, 2010-11 to 2050-51, all scenarios



A5.2 Maximum operational demand outlook – Victoria

- Short term (0-5 years) – maximum operational demand is expected to remain steady across most of the scenarios, driven by decreases in business mass market load and growth in distributed PV uptake.
- Medium to long term (5-30 years):
 - Maximum operational demand is expected to increase steadily from the early 2030s, as a result of increased EV uptake and electrification of industrial loads. EV growth is expected to increase rapidly, with EVs forecast to contribute to around 17% of maximum operational demand by 2040-41 in the Net Zero 2050 scenario and the majority of EVs to still follow a convenience charging profile.
 - The Steady Progress scenario assumes limited electrification impacts, causing the forecasts to be closely aligned with the ESOO 2020 Central scenario.
 - The Slow Change scenario forecasts a more gradual increase to maximum operational demand, in line with the slower economic growth assumed in this scenario.
 - Increased electrification causes large increases in maximum operational demand in the Strong Electrification sensitivity and towards the end of the outlook period in the Net Zero 2050 scenario.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below; these will be presented in future versions of the demand forecasts as an outcome of long-term modelling for the 2022 ISP (see Section 2.5 of the ISP Methodology).

Figure 59 Forecast summer 10% POE maximum operational demand (sent-out) by scenario, Victoria

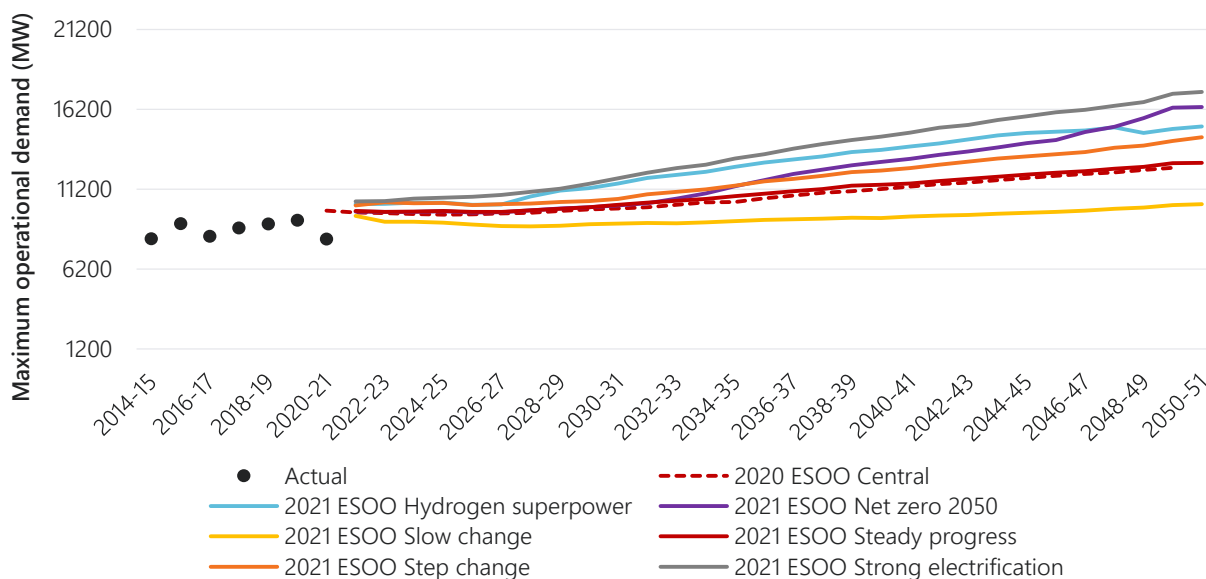


Table 14 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Net Zero 2050 scenario.

Victoria is expected to become winter-peaking by around 2035-36 in one-in-two year demand conditions (50% POE forecast maximum operational demand for winter exceeds that of summer).

The 10% POE summer forecast remain higher than the winter, due to the cooling demand on extremely hot summer days exceeding the heating demand on extremely cold winter days.

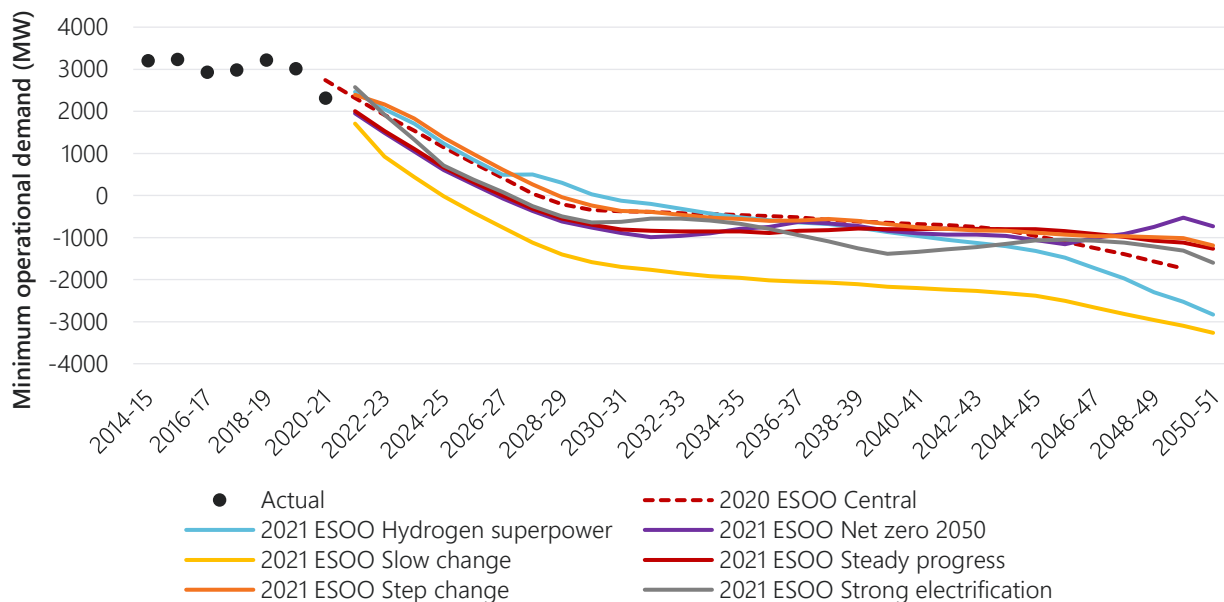
Table 14 Forecast maximum operational demand (sent out) in Victoria, Net Zero 2050 scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2021-22	9,805	8,723	2022	7,569	7,257
2025-26	9,753	8,608	2026	7,853	7,551
2030-31	10,198	9,025	2031	8,645	8,323
2040-41	13,101	11,880	2041	12,629	12,283

A5.3 Minimum operational demand outlook – Victoria

- Short term (0-5 years) – minimum operational demand is expected to decrease rapidly in the short term due to increased distributed PV uptake across all scenarios.
- Medium to long term (5-30 years):
 - Minimum operational demand is expected to continue to decline due to increased distributed PV uptake. The rate at which minimum operational demand decreases is expected to slow down in the early 2030s, due to EV growth, increased battery capacity and electrification across all scenarios.
 - Negative minimum operational demand is expected across all scenarios for most of the forecast horizon.
 - The forecasts for minimum operational demand in the Slow Change scenario lie below the other scenarios, driven down by slower economic growth assumptions.

Figure 60 Forecast annual 50% POE minimum operational demand (sent-out) by scenario, Victoria



A5.4 Supply adequacy assessment – Victoria

Between summer 2020-21 and 2021-22, 865 MW of additional VRE is expected to become available, and 70 MW of large-scale battery storage is expected to be connected, as measured by typical summer capacity. All four units of the 1,450 MW Yallourn Power Station are scheduled to retire in July 2028.

Figure 61 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on capacity during typical summer conditions.

Figure 61 Victoria assumed capacity during typical summer conditions, by generation type, 2020-21 to 2030-31

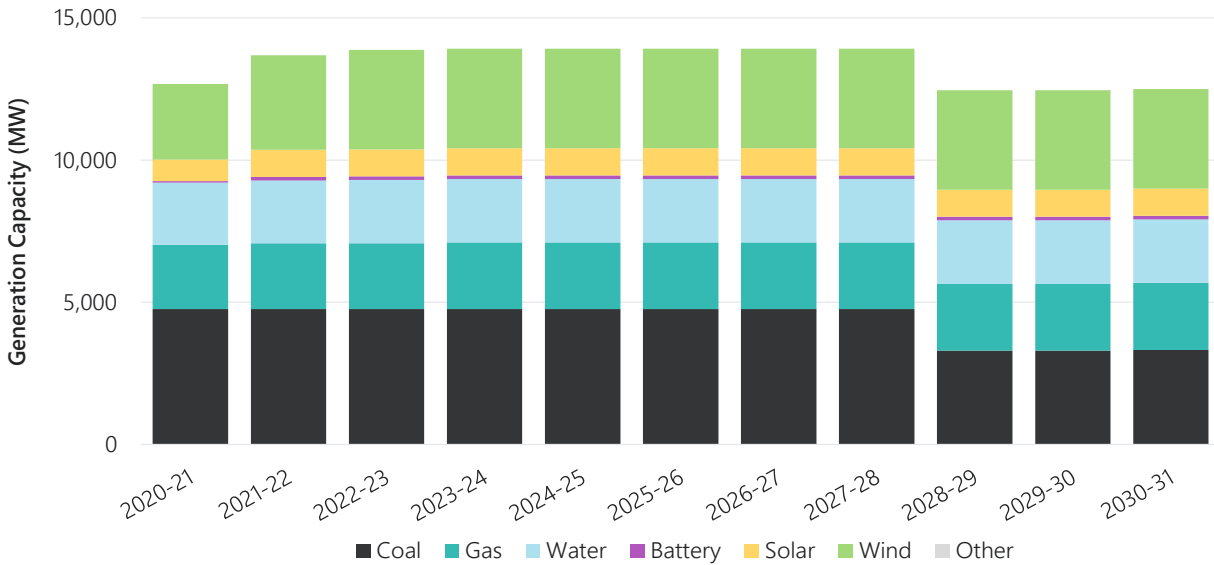
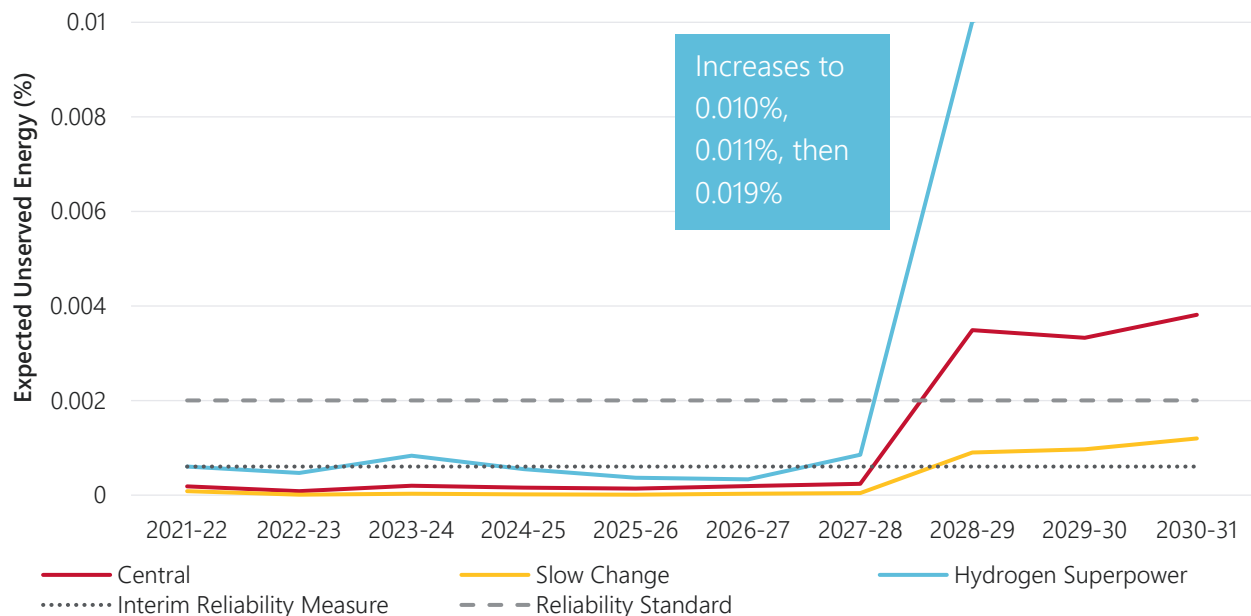


Figure 62 shows forecast USE outcomes for Victoria under the three modelled scenarios:

- In the Central scenario, USE is forecast to remain below both the reliability standard and the IRM until 2027-28. Forecast USE is expected to exceed the reliability standard from 2028-29, following the expected retirement of Yallourn Power Station.
- The Hydrogen Superpower scenario has higher expected USE, demonstrating that additional supply developments would be required to ensure economic viability of hydrogen industries.
- Expected USE remains negligible in the Slow Change scenario due to lower demand assumptions however is still impacted by the retirement of Yallourn Power Station.

Figure 62 Victoria USE forecast by scenario



Possible actions to improve the reliability outlook in Victoria, including projects such as the Jeeralang Battery (that is well progressed), are discussed in Section 5.4.

A5.5 Minimum operational demand assessment – Victoria

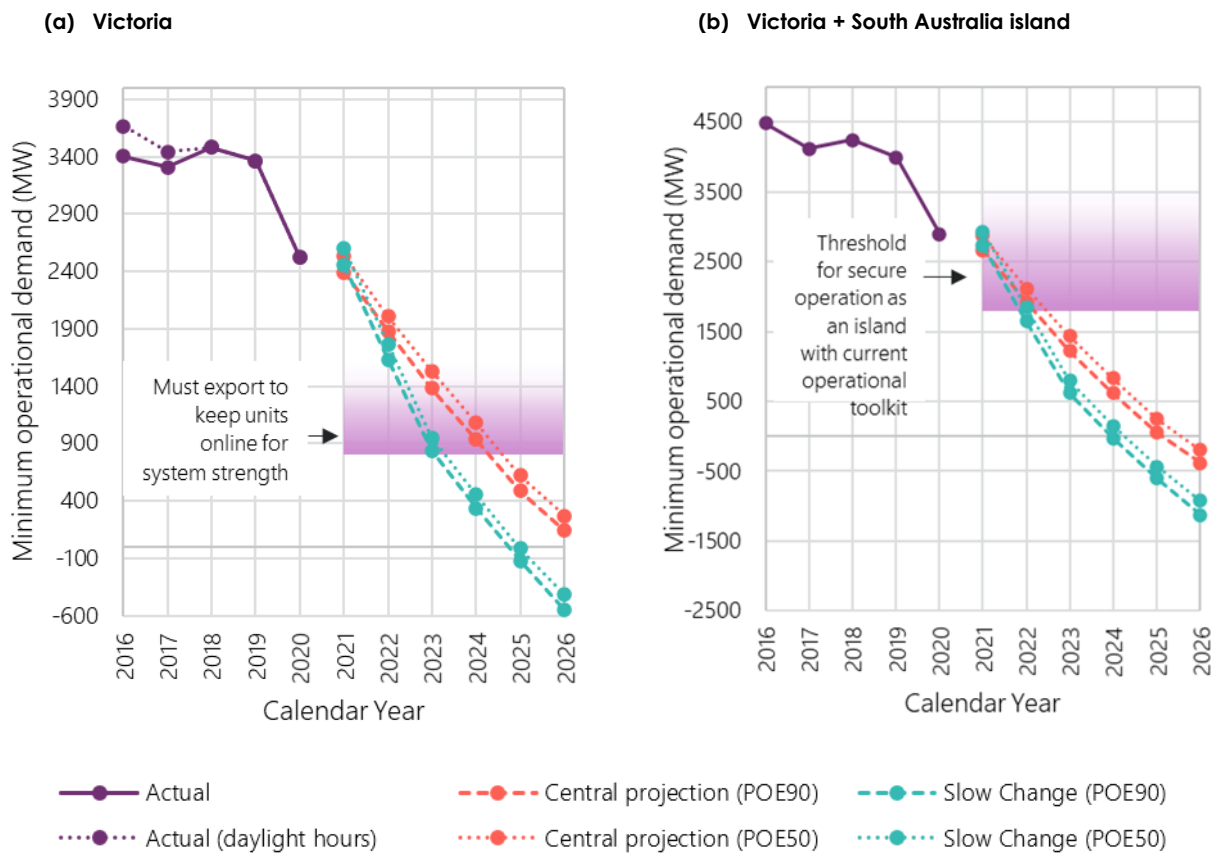
A5.5.1 System normal operation

To maintain adequate system strength in Victoria, various combinations of synchronous units must always remain online, as outlined in AEMO’s transfer limit advice¹²⁵. These combinations have an aggregate minimum generation requirement of 0.8 GW to 1.6 GW. If operational demand falls below this threshold, Victoria must export excess generation to other regions to remain in secure operation.

As Figure 63(a) shows, minimum operational demand in Victoria is expected to start to fall within this threshold range (0.8 GW to 1.6 GW) by 2023 in the Central scenario, and below this threshold range (below 0.8 GW) from 2025. Demand could be lower if there are outages or retirements of major consumers in Victoria.

Exports from Victoria to neighbouring regions may not always be possible, for example, when interconnection to neighbouring regions is limited due to network or stability limits, or when neighbouring regions are simultaneously experiencing low demand. Under these conditions, it may be necessary to shed whole consumer feeders in reverse flows to maintain power system security.

Figure 63 Minimum operational demand thresholds in Victoria



¹²⁵ AEMO, Transfer Limit Advice – System Strength in South Australia and Victoria – June 2021, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

A5.5.2 Victoria and South Australia island

It is possible for Victoria to separate from New South Wales; for example, this occurred on 4 January 2020 due to major bushfires¹²⁶.

Separation could occur in a period when the Basslink interconnector to Tasmania is also unavailable. Basslink has experienced a number of extended outages, in one case almost as long as six months.

This plausible sequence of events could result in an island with South Australia and Victoria connected to each other, but not connected to any other NEM regions (until Project EnergyConnect, VNI West, and/or Marinus Link are commissioned).

Figure 63(b) shows the minimum operational demand threshold required for secure operation of the combined Victoria and South Australia island. This corresponds to the minimum load required to operate the various combinations of synchronous generating units needed to provide required levels of frequency control, inertia, and system strength, across both regions combined¹²⁷ (based on the present assets available, and assuming completed commissioning of the four ElectraNet synchronous condensers in South Australia).

Approximately 1.8 GW to 3.5 GW of operational demand is estimated to be required for the secure operation of a South Australia and Victoria combined island^{128,129,130}.

As shown in Figure 63(b), minimum operational demand levels for the Victoria and South Australia island are already within the range where operational flexibility will be challenging under some circumstances. Operational demand is projected to fall below this range from 2022 to 2023, indicating that shedding of whole consumer feeders may be required to recover sufficient operational demand to maintain power system security, if this series of events occurred in a minimum operational demand period.

¹²⁶ AEMO (September 2020) *Final Report – New South Wales and Victoria Separation Event on 4 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

¹²⁷ Based on existing transfer limit advice for system strength, existing inertia requirements, and the Frequency Operating Standards for an island system. Inter- and intra-regional network limits, such as on the Heywood interconnector, have not been considered in this estimate, and may necessitate a higher demand threshold than that presented.

¹²⁸ This analysis assumes system strength requirements in South Australia are fulfilled with the operation of two significant units (those included in the existing minimum unit combinations) and the four ElectraNet synchronous condensers. System strength combinations for Victoria outlined in AEMO's System Limit Transfer Advice are intended for an interconnected system. However, to operate South Australia and Victoria as a combined island, additional units may need to be directed online to ensure system strength requirements are met. This is reflected in this analysis by adding an additional Loy Yang unit to system normal unit combinations. This analysis assumes that all scheduled generation is curtailed and incorporates a 'return-to-secure' buffer. This buffer ensures that in the event the largest load trips and does not return within 30 minutes, there will be sufficient post-contingency lower FCAS services to operate a secure system. The 'return-to-secure' buffer is equal to the size of the largest post-contingency load. Full BESS FCAS availability is assumed, and 160 MW is added to the thresholds to meet lower regulation FCAS requirements.

¹²⁹ In the 2020 ESOO, the estimated threshold for secure operation of the Victoria and South Australia island was projected to grow rapidly between 2022 and 2023, due to the increasing size of distributed PV disconnection contingencies. Since this analysis was completed, the introduction of the Australian Standard AS/NZS 4777.2:2020 has been confirmed, becoming mandatory from December 2021. This aims to improve the disturbance ride-through capability of distributed PV, and is assumed to prevent this growth in contingency sizes. This reduces the need for additional frequency control reserves to manage the island beyond 2021.

¹³⁰ This analysis assumes the commissioning of the Victorian Big Battery by 2022. It is assumed that the battery provides FCAS and fast frequency response.

A6. Demand side participation forecast

AEMO must publish details, no less than annually, on the extent to which, in general terms, DSP information received under rule 3.7D of the NER has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the NER. This appendix outlines AEMO's DSP forecast for the 2021 ESOO, in fulfilment of its obligation under the NER, and explains the key differences from the 2020 forecast.

A6.1 DSP definition

DSP as forecast by AEMO is a subset of overall demand flexibility and is sometimes also referred to as demand response.

Demand flexibility describes consumers' capability to shift or adjust their demand. This flexibility is usually achieved through use of (automated) technology, but also involves consumers making manual adjustments to load or generation resources, typically in response to price signals.

Demand flexibility exists in many forms, from residential consumers on time-of-use tariffs or using battery storage, to large industrial facilities capable of reducing consumption or starting embedded generators during high price events.

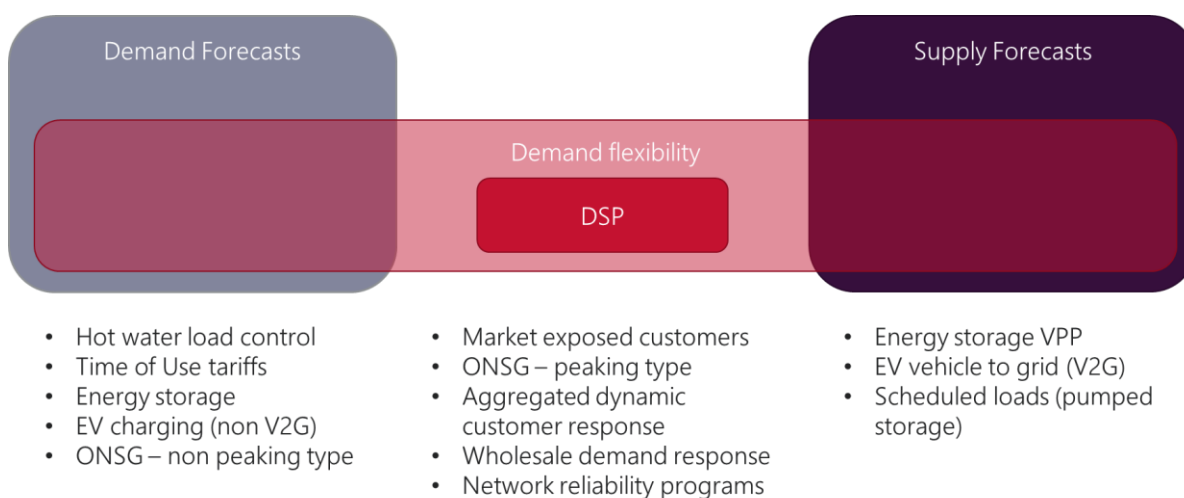
DSP, in AEMO's forecasts, only includes a limited number of categories of demand flexibility – those which are not more effectively represented in the demand forecasts or modelled as an electricity supply resource. All demand flexibility categories are included in AEMO's reliability forecasts, although they are represented differently, depending on the type of demand flexibility, as discussed below and shown in Figure 64:

- The categories listed to the left in Figure 64 are all captured in AEMO's demand forecasts. These generally operate based on daily patterns which are unrelated to wholesale price or reliability signals. This includes an offset from other non-scheduled generation (ONSG) for generators that are not responding to prices.
- Categories that are dispatched as generation (such as aggregated storage systems operated as a VPP) are modelled as supply in AEMO's forecasting processes (right column of Figure 64).
- The categories that are included in DSP are listed in the middle column of Figure 64.

It should also be noted that AEMO's DSP forecast specifically excludes RERT. The DSP forecast is used in the ESOO and the Medium-Term Projected Assessment of System Adequacy (MT PASA), which highlight the risk of shortfalls to determine the need for RERT capacity, so the analysis needs to exclude it in the first instance. One change in this year's forecast, however, is the use of the historical response from capacity on Short Notice RERT last summer as a proxy for potential Wholesale Demand Response (WDR) contributions, when this mechanism¹³¹ is introduced to the NEM in October 2021. This change was presented to stakeholders at the 26 May 2021 Forecasting Reference Group (FRG) meeting.

¹³¹ See <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>.

Figure 64 Flexible demand sources included in AEMO's DSP forecast



A6.2 DSP forecast by component

The forecast was based on DSP information collected by registered participants through AEMO's DSP Information Portal during April 2021. It is mandatory for participants to provide this information to AEMO every year.

The forecast has been broken down into two main components, explained in detail below:

- Price-driven response.
- Reliability response.

Price-driven response

This is determined by examining how flexible loads, as reported to AEMO (including those with embedded generators), have responded to various price levels in recent history¹³². The response is determined as the difference between the observed consumption and the calculated baseline consumption. This is done for an aggregation of sites/programs with similar characteristics for which the same baseline method is appropriate. AEMO uses the 50th percentile as a single point representation of the distribution of responses observed when these price levels have been reached.

A new type of response considered this year is an estimate of the contribution of Demand Response Service Providers (DRSPs) via the WDR mechanism which will come into effect in October 2021. Registration for DRSP first started in June 2021, and minimal voluntary reporting¹³³ occurred through the DSP Information Portal in April 2021. In the absence of detailed participant information being available this year, AEMO assumed the WDR response can be estimated using the 50th percentile of historical responses by price trigger from Short Notice RERT providers¹³⁴. These estimates, once scaled to reasonably match the interest from DRSPs to sign up for WDR ahead of the coming summer, are:

- 16 MW in New South Wales – including 2 MW of firm capacity identified in the DSP Information Portal.
- 4 MW in Queensland.
- 4 MW in South Australia.
- 32 MW in Victoria – including 2 MW of firm capacity identified in the DSP Information Portal.

¹³² The most recent three years of history are used by default.

¹³³ Stakeholders could report expected WDR capacity voluntarily as part of AEMO's DSP data collection process in April 2021.

¹³⁴ From next year, actual dispatch data will be available to guide estimation of the contribution of DRSPs via the WDR mechanism.

Table 15 Price-driven DSP forecast (cumulative response in MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>\$300/MWh	18	22	4	9	3
>\$500/MWh	42	41	12	26	42
>\$1,000/MWh	45	41	14	26	50
>\$2,500/MWh	52	41	18	26	61
>\$5,000/MWh	66	41	23	26	63
>\$7,500/MWh	66	45	33	26	65

For DSP observed when prices exceed \$7,500/MWh, relative to the 2020 ESOO, there is:

- More observed DSP in New South Wales (66 MW compared to 43 MW) and Victoria (65 MW compared to 53 MW).
- A relatively unchanged estimate for Queensland (< 4 MW difference) and Tasmania (<7 MW).
- Less observed DSP in South Australia (33 MW compared to 61 MW).

The most significant change occurred in South Australia, and is attributable to improved baseline models in this region, which showed the 2020 DSP forecast for that region was over-forecast. The increases in New South Wales and Victoria are driven mainly by the included WDR responses.

Reliability response

The reliability response represents the estimated DSP response during reliability events, which AEMO defines as cases where an actual LOR2 or LOR3 is declared¹³⁵.

The estimates are based on the estimated price response for half-hourly price exceeding \$7,500/MWh (50th percentile as above) along with any network event programs and any additional adjustments to reflect responses that have not otherwise been captured¹³⁶.

In this year's program, AEMO has modelled network event programs in Queensland and Victoria. Excluding any loads overlapping with RERT, these amount to:

- 59 MW in Queensland.
- 25 MW in Victoria.

AEMO has been advised these programs are only available in summer, causing different aggregate DSP forecasts to exist for summer and winter.

AEMO has maintained the adjustments made in the 2020 DSP forecast for New South Wales and Victoria, that reflect significant responses observed from RERT providers outside what was contracted (and/or on periods where RERT was not needed). These adjustments reflect the average of the response seen across the periods where LOR2 conditions were in the regions in 2020 and 2021, and sum to:

- 242 MW in New South Wales.
- 122 MW in Victoria.

¹³⁵ See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/reserve-level-declaration-guidelines.pdf.

¹³⁶ The reliability response is estimated with reference to a high price trigger (half-hourly prices rarely reach \$7,500) and during actual LOR2 or LOR3 events prices are often lower than assumed above. This is, however, not considered to have led to any overestimation of DSP, as the level of response is rather consistent at the higher price levels.

Based on this, the combined DSP forecasts for the coming summer 2021-22 and winter 2022 are shown in Table 16 and Table 17 respectively.

The reliability response estimate is the key input to the ESOO process, showing the MW of estimated demand reduction possible to avoid USE during supply shortfalls. As AEMO has no information about committed additional DSP resources, the estimates have been used for the entire 10-year horizon of the ESOO.

Table 16 Estimated DSP responding to price or reliability signals, summer 2021-22

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	18	22	4	9	3
> \$500/MWh	42	41	12	26	42
> \$1000/MWh	45	41	14	26	50
> \$2500/MWh	52	41	18	26	61
> \$5000/MWh	66	41	23	26	63
> \$7500/MWh	66	45	33	26	65
Reliability response	308	104	33	26	212

Table 17 Estimated DSP responding to price or reliability signals, winter 2022

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	18	22	4	9	3
> \$500/MWh	42	41	12	26	42
> \$1000/MWh	45	41	14	26	50
> \$2500/MWh	52	41	18	26	61
> \$5000/MWh	66	41	23	26	63
> \$7500/MWh	66	45	33	26	65
Reliability response	308	45	33	26	187

Reliability response outlook to 2050

The tables above show the DSP forecast for use in the ESOO, only accounting for existing and committed DSP. For longer-term planning studies, such as the ISP, AEMO uses different scenario-specific projections out to 2050 to account for DSP resources that may be developed consistent with the defined scenario settings.

The approach for projecting DSP out to 2050 was discussed in AEMO's 2021 IASR¹³⁷. The resulting projections by scenario out to 2050 was published in AEMO's 2021 Inputs and Assumption Workbook¹³⁸.

¹³⁷ See <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf>.

¹³⁸ See <https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx>.

A6.3 DSP statistics

Understanding the status of demand flexibility in the NEM, both within the categories included in AEMO's DSP forecast and more widely, is important for both market participants, network operators, and policy-makers.

Furthermore, following the rule change on WDR¹³⁹ in 2020, NER clause 3.7D(c) will require AEMO from October 2021 to include analysis of volumes and types of demand response in its reporting, including:

- Information on the types of tariffs used by NSPs to facilitate demand response and the proportion of retail consumers on those tariffs, and
- An analysis of trends, including year-on-year changes, in the DSP information in respect of each relevant category of Registered Participant.

The following presents statistics on the full set of submitted DSP information to provide transparency about demand flexibility in the NEM. As it covers demand flexibility beyond what was included in the DSP forecast, the reported potential in MW differs from the forecast above. Also, two late submissions have been included in the statistics to ensure the most comprehensive coverage of reported DSP in the NEM. The submissions (covering six programs in total) were too late to include in the forecast DSP for this 2021 ESOO, however the impact if included would be minimal.

A6.3.1 Participant programs delivering demand flexibility

Table 18 presents the change in program numbers as submitted by participants to AEMO's DSP Information Portal over time. Note that 2019 was the first year in which all parties with significant DSP resources (to AEMO's knowledge) submitted information, so 2018 data is not directly comparable with subsequent years.

In 2020, in response to the WDR rule change, AEMO was required to review and consult on changes to the DSP information guidelines¹⁴⁰, which resulted in changes being made to the categories of DSP programs available in submissions. The number of programs allocated to the new set of categories is shown in Table 19.

The category change challenges the ability to make direct comparisons to previous years, however it suggests that the new categories are delivering more informative submissions.

A marked decrease in the Other category from 2020 to 2021 is a result of the removal of the requirement that all large (>1 MW) programs fall under this category, which subsequently provides greater insight into the mechanism by which this capacity is being realised in 2021. Notably, there was a substantial increase in the number of market-exposed connection programs. While a large extent of the increase was due to number of sites with embedded generation being reported individually by an entity, which previously were reported in the Other category but are now reported as market-exposed, there is also an increase in market-exposed DSP programs without this change. Any future increases in observed DSP in the NEM as a result of this change will be monitored.

There is also no longer a requirement to report on connections with energy storage systems, as this information is now being collected through AEMO's DER Register. Energy storage systems controlled by an aggregator to respond dynamically to price and/or reliability signals are still required to be reported, although by using the generic DSP categories. From other data entry fields (not shown), it was observed that 15 of the programs have batteries.

¹³⁹ See <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>.

¹⁴⁰ See <https://aemo.com.au/en/consultations/current-and-closed-consultations/dspi-guidelines>.

Table 18 Program numbers from DSP Information Portal, 2018-20

Category	2018	2019	2020
Market exposed connections	12	20	49
Connections on network event tariffs	1	1	7
Connections on retail time-of-use tariffs	20	29	29
Connections with energy storage	7	11	16
Connections with network controlled load	54	58	58
Other (larger programs)	35	45	117

Table 19 Program numbers from DSP Information portal, 2021

Category	2021
Market exposed connections	143
Connections on dynamic event tariffs	5
Directly controlled connections (dynamic operation)	33
Directly controlled connections (fixed schedule)	6
Connections on fixed time-of-use tariffs	49
Other	14

A6.3.2 Statistics by program category

Table 20 summarises category-level information from submissions to AEMO’s DSP Information Portal in 2021. Participants reported each individual consumer connection, based on their national meter identifiers (NMIs), that belong to each program. Some consumer connections may belong to multiple programs; for example, a residential consumer’s NMI could appear both with having controlled hot water tank (directly controlled load) and an interruptible air-conditioner.

The categories containing connections participating in regular demand flexibility incentives – time-of-use tariffs and fixed schedule controlled loads – dominated the total number of connections submitted, capturing large-scale residential and commercial price incentives for time-insensitive loads such as hot water heating and pool pumps. The other very large NMI counts in the directly controlled connections (dynamic operation) mostly capture network programs involving residential appliances that have been deployed to address high or extreme demand events.

Participants may also, for each program, report their firm response in megawatts. Table 20 highlights that, in many cases, the firm response of the program is not known or reported. This makes it more difficult for AEMO to use the provided values as verification of the calculated DSP. AEMO is therefore reliant on the historical analysis of observed responses against estimated baseline consumption.

Table 20 Program statistics grouped by program category for 2021 submissions

Category	Number of programs	Number of connections (connections may appear in more than one program)	Number of programs that included firm response information in submission
Connections on dynamic event tariffs	5	10,784	1
Connections on fixed time-of-use tariffs	49	1,820,784	15
Directly controlled connections (dynamic operation)	33	1,177,147	32
Directly controlled connections (fixed schedule)	6	1,233,995	5
Market exposed connections	143	296,536	21
Other	14	57,544	13

A6.3.3 Load types of reported connections

The types of connections reported to the DSP Information Portal are mainly residential, however a significant portion of the connections were not specified. The load type categories for 2021 are summarised in Table 21, with the numbers of distinct connections reported in 2020 for comparison. The unreported number of NMI for one program in 2020 explains most of the increase in residential connections seen in 2021 that are part of a DSP program.

Table 21 Load types of reported connections

Load type	Number of distinct connections (2020)	Number of distinct connections (2021)	Dominant program category in each load type as percentage (2021)
< not specified >	1,701,821	2,500,874	69% connections on fixed time of use tariffs
Commercial	2,884	10,806	99% market exposed connections
Industrial	361	92	100% market exposed connections
Residential	1,674,967	2,085,018	56% directly controlled connections (dynamic operation) 36% directly controlled connections (fixed schedule)

A6.3.4 Number of connections by category and type

Table 22 lists the number of connections in each category, but also by DSP type. This table also includes the sum of all reported firm MW responses of each program, including programs excluded from AEMO's DSP calculation. In total, it suggests 1,930 MW of firm response exists, although more could be unquantified or simply not reported. As noted, this estimate include number of programs not included in AEMO's DSP forecast, and it is therefore not comparable to the forecast presented in Table 17.

Table 22 Number of connections grouped by program category and DSP type

Category	DSP type	Distinct number of connections	Reported sum of firm response (MW)	Number of programs
Market exposed connections	Embedded generation	269,173	440	68
	Energy storage	16,600	0.75	5
	Load reduction	9,595	0	31
	Load reduction; Embedded generation	5	0	1
	<not specified>	1,163	64	38
Connections on dynamic event tariffs	Embedded generation	4	0.5	1
	<not specified>	10,780	0	4
Directly controlled connections (dynamic operation)	Commercial	23	38	4
	Embedded generation	7	15	3
	Energy storage	1,095	2	4
	Load reduction	1,172,763	868	8
	<not specified>	3,259	65	14
Directly controlled connections (fixed schedule)	Energy storage	22	1	1
	Load reduction	760,226	100	2
	<not specified>	473,747	111	3
Connections on fixed time-of-use tariffs	Energy storage	57	1	1
	Load reduction	101,629	0	1
	<not specified>	1,719,098	101	47
Other	Embedded generation	14	21	1
	Energy storage	1,083	5	1
	Load reduction	52,326	65	9
	<not specified>	4,121	31	3

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A8. Abbreviations

Abbreviation	Term
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BESS	battery energy storage system
BMM	business mass market
CMSL	Contingency and Minimum System Load
DER	distributed energy resources
DNSP	distribution network service provider
DSP	demand side participation
ESB	Energy Security Board
ESOO	<i>Electricity Statement of Opportunities</i>
EV	electric vehicle
FCAS	frequency control ancillary services
FFR	fast frequency response
GW	gigawatts
GWh	gigawatt hours
IASR	<i>Inputs, Assumptions and Scenarios Report</i>
IBR	inverter-based resources
IRM	Interim Reliability Measure
ISP	<i>Integrated System Plan</i>
kV	kilovolts
kW	kilowatts
LIL	large industrial load
LNG	liquified natural gas
LOLP	loss of load probability
LOR	Lack of Reserve
MVA	megavolt-amperes

Abbreviation	Term
MW	megawatts
NEM	National Electricity Market
NER	National Electricity Rules
NSCAS	Network Support and Control Ancillary Services
PEM	proton exchange membrane
PJ	petajoules
POE	probability of exceedance
PV	photovoltaic
QNI	Queensland New South Wales Interconnector
RERT	Reliability and Emergency Reserve Trader
REZ	renewable energy zone
RRO	Retailer Reliability Obligation
SIPS	System Integrity Protection Scheme
TNSP	transmission network service provider
TWh	terawatt hours
UFLS	under frequency load shedding
USE	unserved energy
VNI	Victoria New South Wales Interconnector
VPP	virtual power plant
VRE	variable renewable energy
WDR	Wholesale Demand Response