Energy Security Target Monitor Report

October 2022

A report for the New South Wales Minister for Energy

Important notice

Purpose

This Energy Security Target Monitor report is provided to the New South Wales Minister for Energy by AEMO in its role as the energy security target monitor, under section 13(7) of the *Electricity Infrastructure Investment Act 2020* (NSW) as in force at the date of this report. It is not intended to be used or relied on for any purpose other than as contemplated by that legislation.

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Version control

Version	Release date	Changes
1	28/10/2022	Confidential publication for the Minister for Energy

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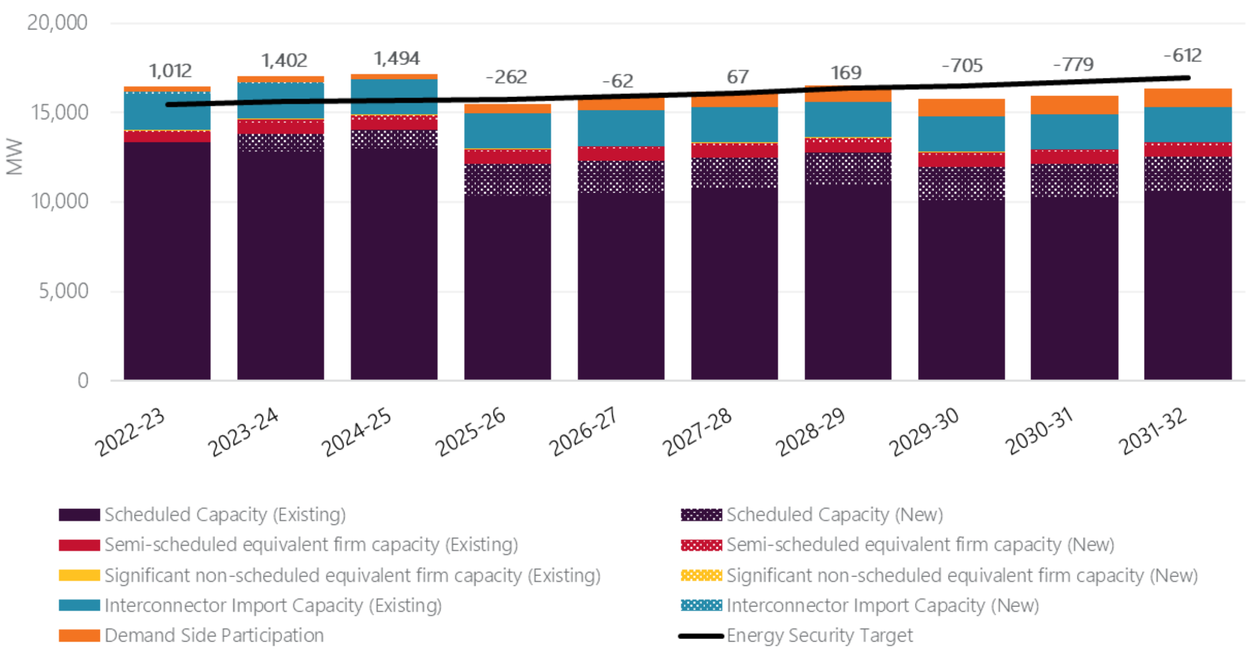
Executive summary

The Energy Security Target (EST) Monitor Report assesses whether forecast firm capacity in New South Wales is sufficient to meet the EST defined in the *Electricity Infrastructure Investment Act 2020* (NSW)[1] for each of the next 10 financial years. The EST sets the target capacity required to meet forecast New South Wales maximum consumer demand in summer, with a reserve to account for the unexpected loss of the two largest generating units in the state. The assessment uses scenarios and inputs from AEMO's 2022 Electricity Statement of Opportunities (ESOO)[2], but with some variations and simplifications required to align with the intent of the EST.

Firm capacity includes the capacity from generation, storage, interconnector, and demand side participation (DSP) sources likely to be available to New South Wales electricity customers during times of summer peak demand. It focuses on existing and projected new sources where there has been a formal commitment to construct. The construction of new infrastructure to meet the objectives of the *Electricity Infrastructure Investment Act 2020* (NSW) has not been included in this assessment, because there are not yet any Long-Term Energy Service Agreements in place.

Figure 1 shows AEMO's Central scenario forecast for the 10-year EST outlook. AEMO forecasts an EST breach in 2025-26 to 2026-27 following the expected closure of Eraring Power Station. The breach is however relatively small due to the development of the New South Wales System Integrity Protection Scheme (NSW SIPS), which considerably improves the outlook from 2025-26 to 2029-30. A breach is again forecast from 2029-30 onwards following the expected closure of Vales Point Power Station.

Figure 1 Central scenario, assessment of the EST



[1] See https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044#pt.3.

[2] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf.

While EST breaches are forecast in 2025-26, 2026-27 and from 2029-30 when considering only committed projects, additional generation, storage and transmission projects are anticipated or are deemed actionable in the 2022 *Integrated System Plan* (ISP)[3]. These projects – which include the Hunter Transmission Project and the HumeLink transmission project – are forecast to significantly increase intra-regional transfer limits into the Sydney-Newcastle-Wollongong sub-region, thereby allowing already committed firm capacity to be available to New South Wales electricity customers during peak demand periods. When these projects are also considered, the forecast instead projects EST surpluses from 2027-28, as shown in Figure 2.

Further, the New South Wales Minister for Energy has directed the Consumer Trustee to run a new tender[4], which anticipates at least 350 megawatts (MW) of firming infrastructure by 2025-26, located in the Sydney-Newcastle-Wollongong sub-region.

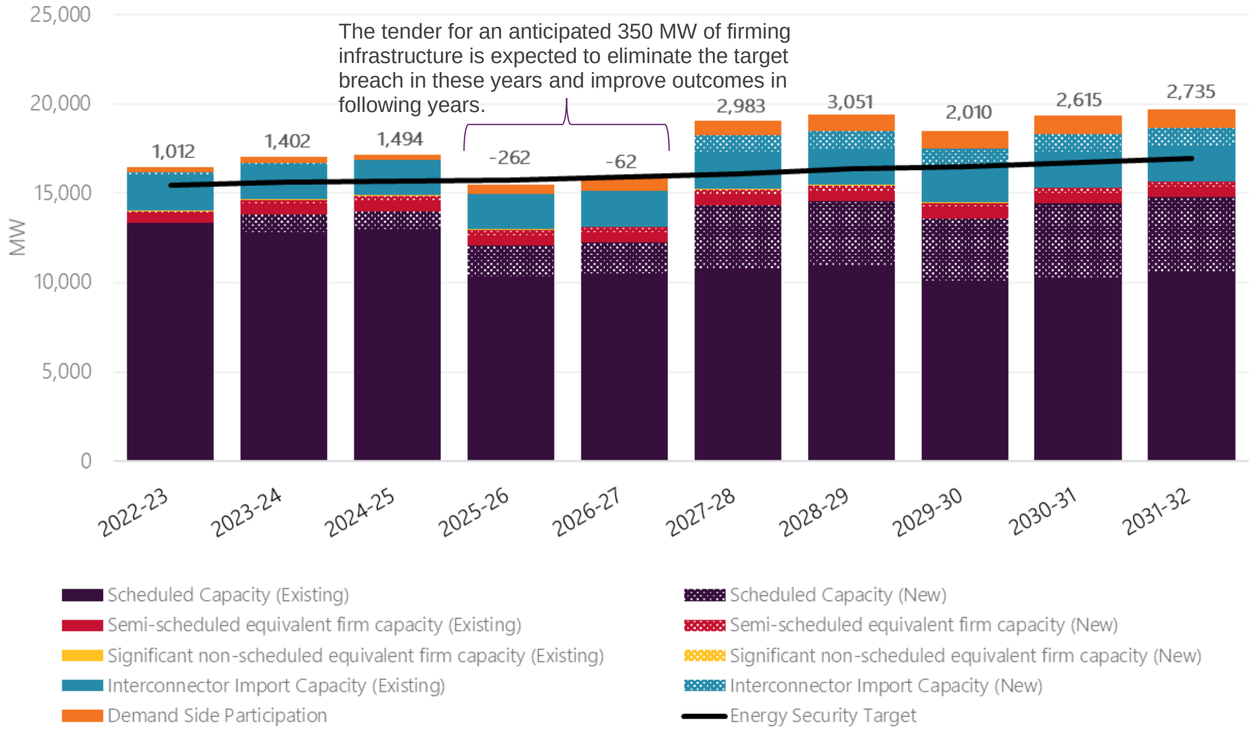
Combined, these projects are forecast to resolve all EST breaches over the 10-year EST assessment horizon.

From 2029-30, following the retirement of Vales Point Power Station, the modelled surplus is highly dependent on:

- Inter-regional transfer capacity, which does not currently consider the availability of generation in neighbouring regions, and
- Short duration storage, which does not currently consider the full availability of energy over periods of supply scarcity.

AEMO recommends further investigation of these factors in future versions of the relevant New South Wales regulations to ensure EST assessments accurately describe the risks to New South Wales electricity consumers.

Figure 2 Anticipated and actionable sensitivity, assessment of the EST



[3] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[4] See https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap/energy-security-target-monitor.

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1 Introduction

The Energy Security Target (EST) Monitor Report assesses whether forecast available firm capacity in New South Wales is sufficient to meet the EST defined in the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act)[5] for each of the next 10 financial years. The EST sets the target capacity required to meet forecast New South Wales maximum consumer demand in summer (measured using a 10% probability of exceedance (POE)), with a reserve to account for the unexpected loss of the two largest generating units in the state.

AEMO has been appointed as the EST monitor, a role defined in the EII Act. As EST monitor, AEMO provides a forecast of the EST and any projected breach of the EST (target breach) for each of the next 10 financial years, calculated consistently with the EII Act and the Electricity Infrastructure Investment Regulation 2021[6] (the EII Regulation).

For the purposes of section 14(3) of the EII Act, in AEMO's opinion, this report does not contain information the disclosure of which could reasonably be expected to:

(a) diminish the competitive commercial value of the information to the person who provided the information to AEMO, or

(b) prejudice the legitimate business, commercial, professional or financial interests of the person who provided the information to AEMO.

[5] See https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044#pt.3.

[6] See https://legislation.nsw.gov.au/view/html/inforce/current/sl-2021-0102.

2 Inputs and assumptions

For this EST assessment, AEMO has adopted inputs and assumptions used to produce the 2022 Electricity Statement of Opportunities (ESOO)[7] and/or other relevant assumptions from AEMO's 2022 Forecasting Assumptions Update (FAU)[8], unless otherwise stated.

Key assumptions are outlined in the following sections.

2.1 Maximum demand

In calculating the maximum demand for a financial year consistent with the EII Regulation, clause 13, AEMO:

- Took into account the most recent forecast of maximum operational demand as sent out in New South Wales in summer, as published by AEMO in the 2022 ESOO. Consistent with the 2022 ESOO, AEMO considers the Step Change scenario to be most likely, and therefore the Central scenario. This varies from the 2021 ESOO which considered the Progressive Change scenario as most likely, or Central.
- Included the forecast of generating unit auxiliaries based on that forecast by AEMO in the 2022 ESOO to reflect the maximum demand as generated by generating units in New South Wales in summer.
- Took into account the forecast use of distributed energy resources (DER) in New South Wales, as specified in the 2022 ESOO.

Maximum operational demand means the highest level of electricity drawn from the grid at any one time in a financial year. In the 2022 ESOO, maximum operational demand is forecast to occur in summer in New South Wales for each of the forecast financial years. The 10% POE forecast implies that the forecast is expected to be exceeded once in every 10 years.

Figure 3 explains AEMO's demand definitions. Further detail is provided in AEMO's 2022 ESOO[8].

The demand forecasts used to assess the EST incorporate assumptions around continued energy efficiency investments, uptake and operation of DER including distributed photovoltaic (PV) systems, battery storage systems, and electric vehicles (EVs), as well as projected generator auxiliary load.

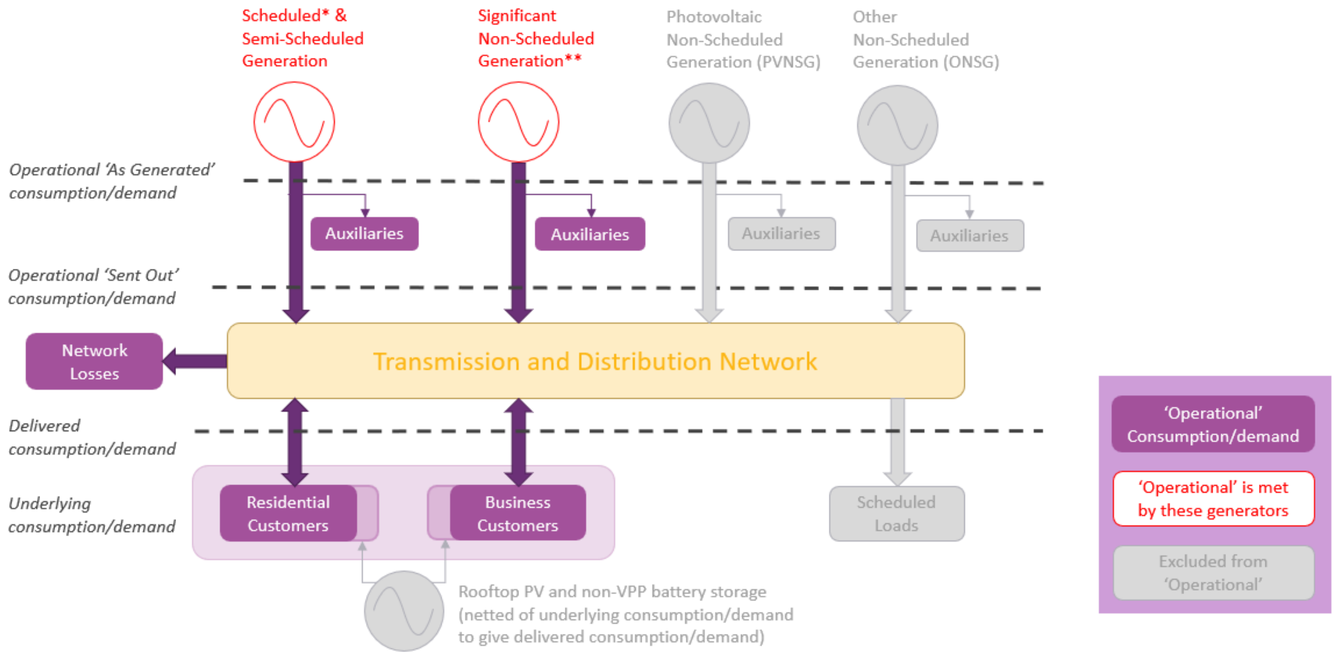
Further changes to the New South Wales Energy Savings Scheme in December 2020, including the Peak Demand Reduction Scheme (PDRS)[9], are considered committed developments, and are included in AEMO's demand forecasts. As such, they are implicitly captured in this EST assessment.

[7] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf.

[8] At https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/final-2022-forecasting-assumptions-update.pdf.

[9] See https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme

Figure 3 AEMO demand definitions



* 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.

2.2 Firm capacity

The EII Regulation, clauses 14 and 15, provides that the calculation of firm capacity for the EST includes scheduled, semi-scheduled, and appropriate non-scheduled generation (including storage) from existing and projected new sources. This is consistent with AEMO's definition of operational demand (see Figure 3). Firm capacity for an EST forecast year should also account for forecast interconnector capacity, demand response, and demand side participation (DSP).

This section describes how AEMO has determined each of these elements of the firm capacity calculation.

2.2.1 Existing scheduled generation and storage capacity

The available firm capacity of scheduled generators and storage was taken as the summer peak rating for each unit from the August 2022 Generation Information publication[10]. This incorporates temperature de-rating of the units based on their expected response to high temperatures during 10% POE demand conditions.

2.2.2 Existing semi-scheduled generation capacity

The EII Regulation, clause 15(2), stipulates that the available equivalent firm capacity of semi-scheduled generators like wind farms and large-scale solar farms, must be estimated considering:

- The amount of electricity produced, at times of peak demand in summer over the past three financial years, and

[10] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

- The amount of electricity likely to be produced, at times of peak demand in summer by generating units forecast to be available.

For this purpose, AEMO has calculated peak contribution factors for wind and solar technologies in New South Wales representing the level of generation that can be relied on from semi-scheduled generators at times of peak demand. To have confidence that this capacity is firm, the peak contribution factors are based on a 90% POE calculation; that is, nine times out of 10, wind farms and large-scale solar farms could be expected to generate at or above the assumed firm capacity during peak demand periods.

To derive these peak contribution factors, AEMO calculated:

1. The top 10 days for operational maximum demand during the last three summers (2019-20, 2020-21 and 2021-22). Ten days were chosen for the 2022 EST assessment to ensure a reasonable sample size of high demand days and to address the low number of days that met the criteria used in the 2021 EST assessment (previously days with demand above 12,500 megawatts (MW) were selected).
2. Observed aggregate semi-scheduled capacity factors (generation as a proportion of summer typical capacity) for wind and solar generators on these top 10 days for operational maximum demand.
3. The 10th percentile of these observed aggregate capacity factors (meaning that 90% of observed aggregate capacity factors exceeded this percentile).

Figure 4 shows the calculated peak contribution factors derived using the above method for numerous intervals of the days of interest. Factors derived for solar trend downwards, showing that solar generation is unlikely later in the evening. Factors derived for wind technologies slightly increase after 6:30 pm National Electricity Market (NEM) time, with an approximate firm contribution between 10-20%.

Figure 4 10th percentile capacity factors for top 10 summer days

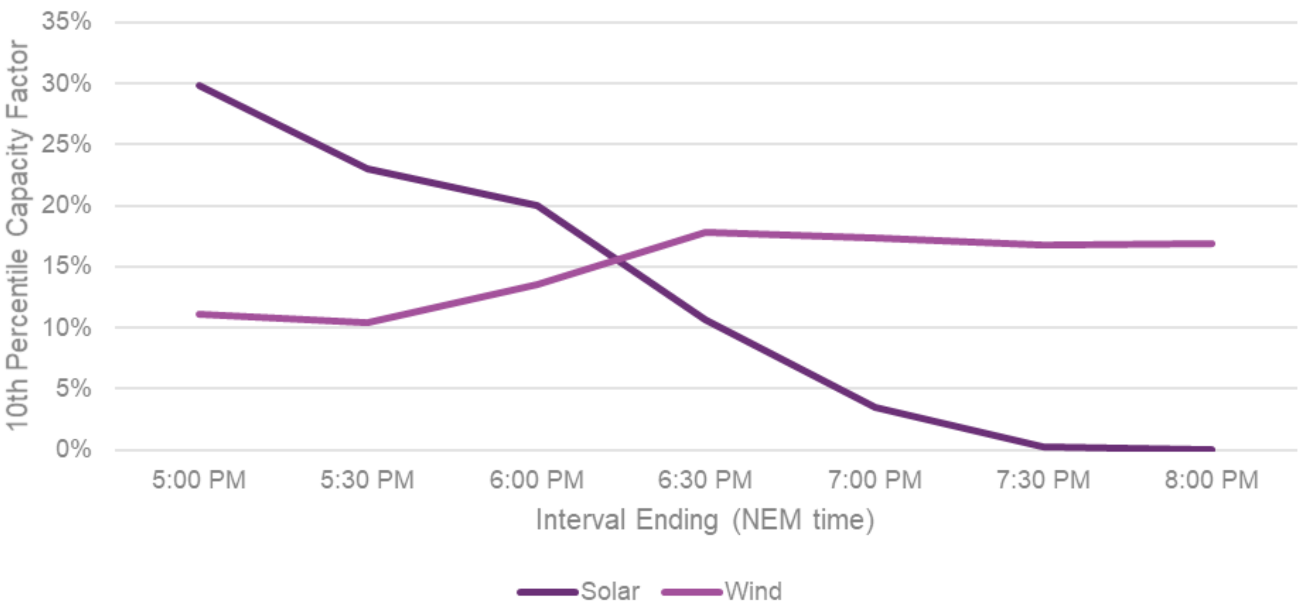
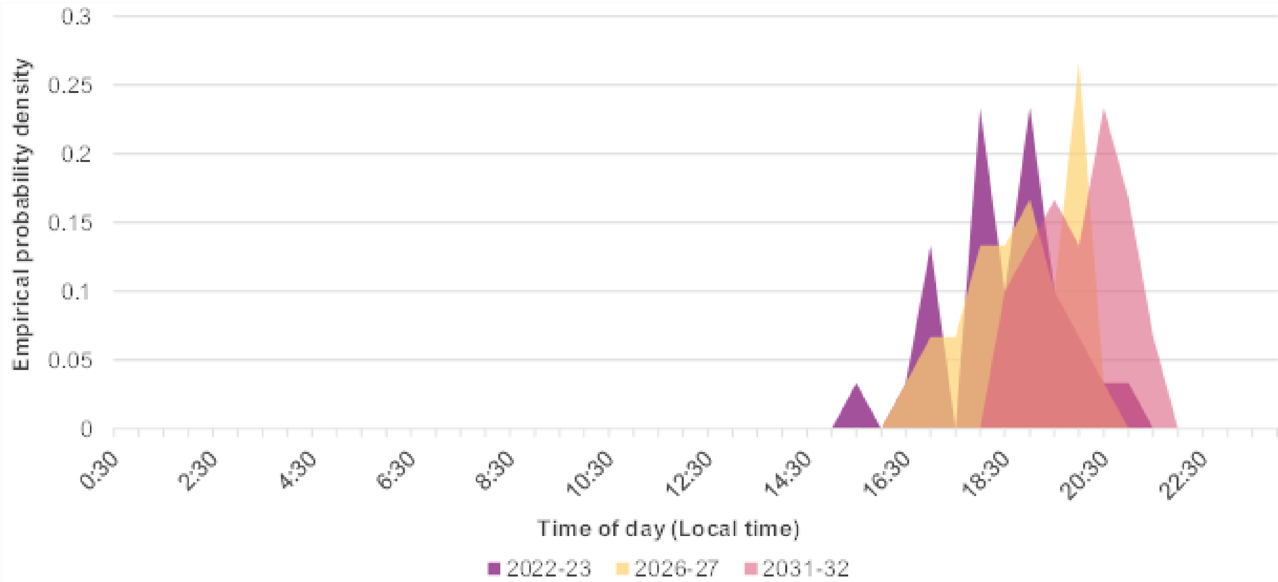


Figure 5 shows the probability distribution of forecast maximum demand for New South Wales summer in local time. While some time-shifting is forecast over the 10-year horizon, uncertainty in the timing of maximum demand remains substantial.

For the purposes of the 2022 EST assessment, AEMO has selected the 6:30 pm NEM time (7:30 pm local daylight savings time) interval to represent the maximum demand interval for the entire forecast horizon. This selection is half an hour later from that chosen in the 2021 EST assessment, but better aligns with the median time of maximum demand over the 10-year horizon. Any changes to semi-scheduled equivalent firm capacity observed over the horizon are therefore driven by new capacity, rather than the timing of maximum demand.

Figure 5 Central forecast showing change in distribution of time of 50% POE summer maximum demand in New South Wales, 2022-23 to 2031-32



Based on the above assumptions, the peak contribution factor applied in this 2022 EST Monitor Report is estimated to be 17.9% for wind and 10.7% for solar. These factors differ from those calculated in the 2021 EST Monitor Report of 13.7% for wind and 14.9% for solar.

These capacity factors are applied to the Summer Typical capacity from the August 2022 Generation Information publication[11] to determine the available equivalent firm capacity of existing semi-scheduled generators.

2.2.3 Existing significant non-scheduled generation capacity

Significant non-scheduled generators are wind and solar non-scheduled generators with a capacity greater than or equal to 30 MW[12] (Table 1). The available capacity of significant non-scheduled generators was calculated on the same basis as semi-scheduled generators, using the peak contribution factors previously described.

Table 1 Existing significant non-scheduled generators in New South Wales

Generator	Nameplate capacity (MW)
Capital Hill Wind Farm	140.7
Cullerin Range Wind Farm	30

[11] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[12] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data/generation-and-load for more detail on those generators included or excluded from the definition of operational demand.

2.2.4 Generator closures

Expected closure years for all existing generators were taken from the August 2022 Generating unit expected closure year and Generation Information publications[13]. Unit closure was assumed to occur after summer for the year specified; for example, Vales Point B, which is expected to close in 2029, was considered available for the 2028-29 summer, and unavailable for the entire 2029-30 summer.

2.2.5 Proposed generation and storage projects

The EII Act requires that the following proposed firm generation and storage capacity must also be taken into account in the EST projection, provided AEMO considers it likely to be available to New South Wales electricity customers in the financial year:

1. Projects that have made a formal commitment to construct according to AEMO's Generation Information page.
   - AEMO has included all projects 'committed' or 'committed*'[14] in the August 2022 Generation Information publication, including the Snowy 2.0 pumped hydro project (1,998 MW) and Kurri Kurri gas peaking plant (660 MW), with justification for inclusion consistent with the ESOO methodology.
2. Projects that will be constructed and operated under a Long-Term Energy Service (LTES) Agreement.
   - Currently there are no projects under LTES Agreements.
3. Projects that will be constructed under funding programs run by, or on behalf of, a New South Wales Government or Commonwealth Government agency.
   - Table 2 includes details of the projects considered on this basis; two known projects listed here are not included in the EST projection, on advice from the New South Wales Office of Energy and Climate Change that suggests they are insufficiently advanced.

Firm and equivalent firm capacity from proposed generation and storage projects was calculated using the same methodology as applied for existing projects.

[13] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[14] Committed projects are those that will proceed, with known timing, satisfying all five of the commitment criteria. Committed* projects are those that are highly likely to proceed, satisfying Land, Finance and Construction criteria plus either Planning or Components criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced. For more information see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Table 2 Additional projects that will be constructed under New South Wales Government or Commonwealth Government funding programs

Project	Expected completion date	Firm capacity (MW)	Included in EST assessment
Waratah Super Battery [A]	To operate between 2025-26 and 2029-30	700 MW battery that is expected to provide 910 MW of firm capacity.	Yes
CWP Renewables' Sapphire Battery Facility	In advance of 2023-24 summer	30	Yes
UPC/AC Renewables Australia's New England Solar Farm Battery	In advance of 2023-24 summer	50	Yes
Darlington Point Battery Energy Storage System (BESS)	In advance of 2023-24 summer	150	Yes
Goldwind Australia's hybrid gas reciprocating engine and battery project	To be determined	84	No
SolarHub's Smart Distributed Batteries	To be determined	6	No

Note: data is predominantly derived from https://energy.nsw.gov.au/renewables/clean-energy-initiatives/emerging-energy-program.
A Akaysha Energy have announced their intention to build the Waratah Super Battery as an 850 MW battery, however only 700 MW is subject to New South Wales government support and the remainder is therefore not included in this assessment. The NSW SIPS functionality is expected to be contracted on a 'sculpted seasonal core' basis with varying capacity between SIPS and merchant battery depending on the time of day and time of year. Energy Co has advised that the maximum total firm capacity attributable to the 700 MW battery component is 910 MW, which has been incorporated in this assessment as part SIPS and part merchant battery.

2.2.6 Existing and proposed interconnector capacity

Interconnector import capacity, assumed to be operating under summer peak demand conditions, also contributes to firm capacity in the calculation of the EST.

This includes firm capacity from proposed interconnector augmentations, if AEMO considers the capacity likely to be available to New South Wales electricity customers in the financial year, including:

1. Interconnectors for which a revenue determination has been made under rule 6A.4 of the National Electricity Rules.
2. Interconnectors for which a determination has been made under section 38 of the EII Act.
3. Interconnectors under a priority transmission infrastructure project to which a direction under the EII Act, section 32(1)(b), relates.

Import capability for existing and applicable new interconnectors has been taken from the 2022 FAU and is summarised in Table 3.

Table 3 Import capabilities between sub-regions at peak demand

Interconnector	New South Wales import capability (MW)
NNSW – SQ ("Terranora")	130
NNSW – SQ ("QNI")	1,145 (plus an additional 60 MW from 2023-24 following completion of the Queensland – New South Wales Interconnector (QNI) Minor upgrade)
VIC – SNSW ("VNI")	870 (including Victoria – New South Wales Interconnector (VNI) Minor, which is completed by 2022-23).
SNSW – SA ("Project EnergyConnect")	800 (from 2026-27 once PEC fully commissioned and tested)

The following additional projects have been considered in addition to the existing firm capacity:

- The **Queensland – New South Wales Interconnector (QNI) Minor** upgrade by mid-2023.
- The **Victoria – New South Wales Interconnector (VNI) Minor** upgrade by November 2022.
- **Project EnergyConnect**, with timing that reflects the expected completion of commissioning and inter-network testing by July 2026 (one year after the 2021 EST monitor report assumption).

2.2.7 Major transmission limits

Major intra-regional transmission limits can reduce the amount of electricity available to New South Wales customers from firm generation, storage, and interconnector capacity. Consistent with the EII Regulation, clause 15(4), firm capacity for a financial year is calculated with consideration of these constraints.

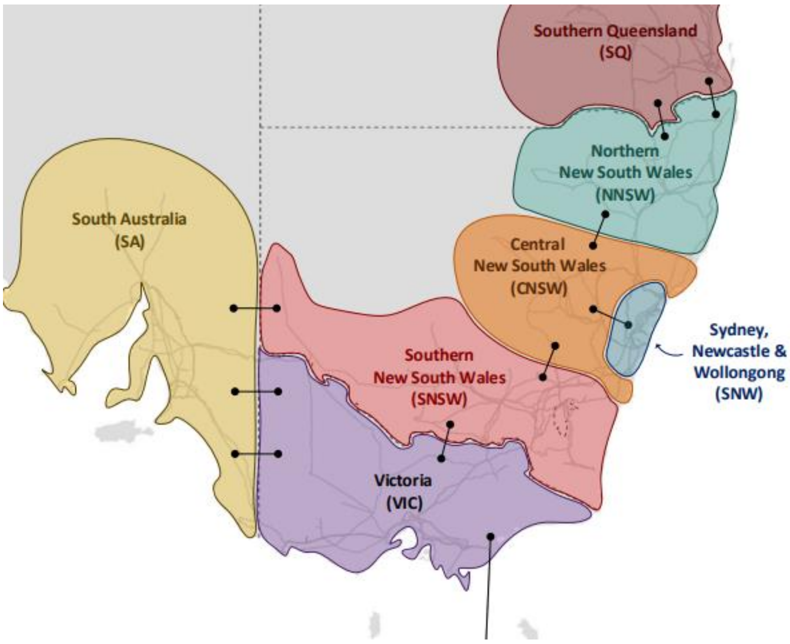
To do so, AEMO estimates the impact of intra-regional transmission limits on the ability for firm capacity to reach the majority of customer load in the Sydney-Newcastle-Wollongong areas, and discounts the firm capacity accordingly.

As the EST calculation is intended to be a simple deterministic calculation that is relatively easy to understand, a sub-regional representation of the New South Wales network was used to estimate the major network constraints as is defined in the 2021 *Inputs, Assumptions and Scenarios Report* (IASR)[15].

The key New South Wales sub-regions are highlighted in Figure 6, two of which capture the most relevant intra-regional transmission limits:

1. **Sydney-Newcastle-Wollongong (SNW)** – this identifies any major transmission limits that may constrain supply from the Central New South Wales sub-region into the major demand centre for New South Wales.
2. **Central New South Wales and SNW (CNSW + SNW)** – this identifies any major transmission limits that may constrain supply from the Northern and Southern New South Wales sub-regions into the Central sub-region.

Figure 6 Sub-regional model as documented in the IASR



[15] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

To test whether these major transmission limits impact the EST, AEMO first assessed the EST against each relevant sub-region separately. It was assumed that sub-regional firm capacity plus imports up to the transmission limit must be sufficient to meet the maximum demand in that sub-region even in the event that the two largest units in the sub-region are unavailable.

Where the sub-regional reserve estimates result in a target surplus/breach that is lower/higher than the whole of the New South Wales target surplus/breach, the difference was assessed as the impact of the major intra-regional transmission limit. If major intra-regional transmission limits were identified, proposed firm capacity forecast to connect was discounted in the following order:

1. Proposed inter-regional transfer capacity is discounted up to the full capacity of all proposed inter-regional transmission developments.
2. Should the intra-regional transmission limit be greater than the forecast proposed inter-regional transfer capacity, proposed scheduled capacity will be discounted up to the full capacity of all proposed scheduled generation forecast to connect outside the sub-region impacted by the intra-regional congestion.
3. Should the intra-regional transmission limit be greater than the sum of proposed inter-regional transfer capacity and proposed scheduled generation outside the impacted sub-region, proposed semi-scheduled capacity will be discounted up to the full firm capacity of all proposed semi-scheduled generation forecast to connect outside the sub-region impacted by the intra-regional congestion.

In the 2022 assessment, only proposed firm capacity was discounted, on the basis that the current existing firm capacity is not expected to be materially discounted by major constraints on transmission infrastructure. In future assessments where the proposed firm capacity becomes existing firm capacity, the implementation will require review to ensure this capacity is appropriately limited consistent with the sub-regional model.

For the purposes of the calculation of a target surplus/breach for each sub-region, the following inputs have been used:

- Sub-regional 10% POE maximum demand, as estimated in the 2011 reference year[16], as summarised in Table 4.
- Auxiliaries were assumed as a ratio of maximum potential sub-regional aggregate auxiliaries to the maximum potential regional aggregate auxiliaries[17].
- Reserves were calculated as the two largest generating units in the sub-region.
- Firm and equivalent firm capacity as available in the sub-region.
- Intra-regional transmission import capabilities between sub-regions, as summarised in Table 5.

[16] From the sub-regional traces published on https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Sub-regional forecasts are not published in any AEMO publication; hence the 2011 reference year was chosen as the first available from the selection of traces. Annual maximums were taken from these published 10% POE traces and were scaled to the traces published in the 2022 ESOO.

[17] Forecast sub-regional auxiliaries are not published by AEMO, however unit level auxiliaries at time of maximum demand are published by technology aggregate. These technology aggregates are used to scale the maximum potential generator auxiliaries to the ESOO forecast for auxiliaries at time of maximum demand based on available generators in each sub-region.

Table 4 Assumed sub-regional 10% POE maximum operational demand Central forecasts (MW, as generated)

	CNSW + SNW	SNW
2022-23	11,756	10,601
2023-24	11,835	10,630
2024-25	11,895	10,666
2025-26	11,996	10,741
2026-27	12,057	10,782
2027-28	12,166	10,883
2028-29	12,365	11,067
2029-30	12,479	11,173
2030-31	12,668	11,336
2031-32	12,867	11,527

Table 5 Import capabilities between sub-regions at peak demand

Intra-regional limit	Intra-regional import capability (MW)
SNSW –> CNSW	2,700 (plus an additional 740MW from either SNSW->CNSW or NNSW->CNSW between 2025-26 and 2029-30 due to the operation of the NSW SIPS)
NNSW –> CNSW	930 (plus an additional 740MW from either SNSW->CNSW or NNSW->CNSW between 2025-26 and 2029-30 due to the operation of the NSW SIPS)
CNSW –> SNW	6,125 + 0.33 * (Eraring+Vales Point) generation (plus an additional 740MW between 2025-26 and 2029-30 due to the operation of the NSW SIPS)

Source: https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update.

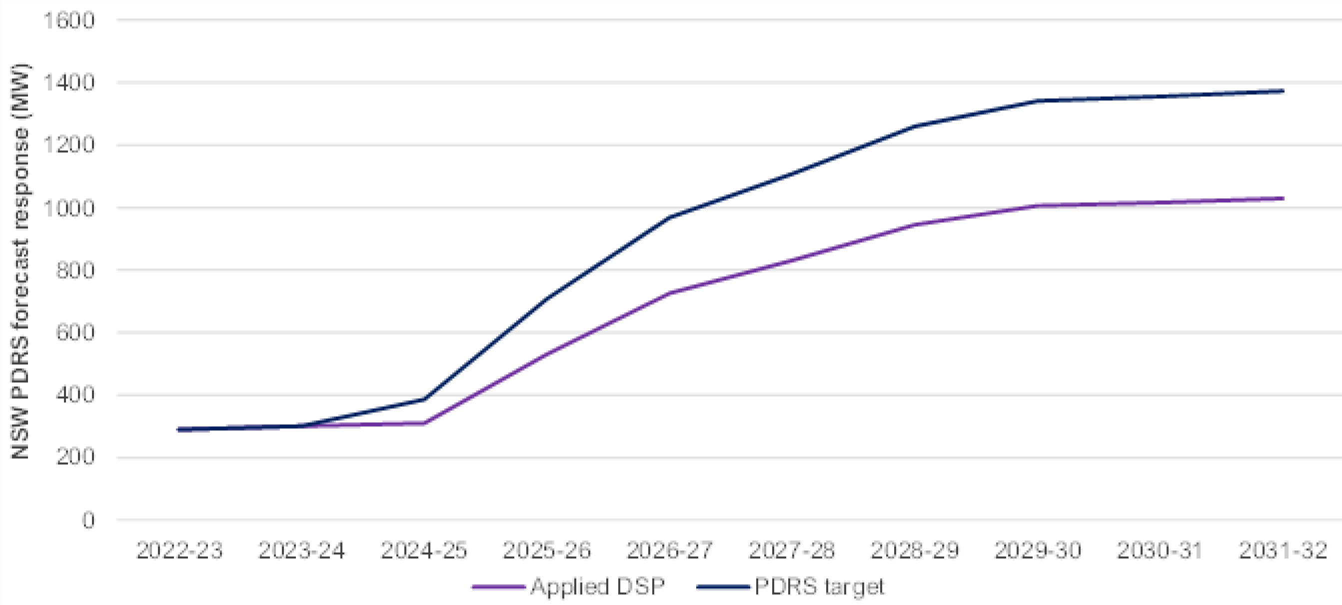
2.2.8 Demand response and demand side participation

Demand response and DSP are both considered as firm capacity in the calculation of the EST and were both included in AEMO's DSP forecast, as published in the 2022 ESOO. The amount of DSP assumed includes only existing and committed DSP projects, consistent with the 2022 ESOO Central scenario.

The committed NSW Peak Demand Reduction Scheme (PDRS) policy will create a financial incentive to reduce electricity consumption during peak times in New South Wales. AEMO included this scheme in all scenarios, resulting in a DSP forecast which increases over time. The PDRS has been applied from 2022-23 with the target growing to 10% of forecast peak demand by 2029-30 and then staying as a constant percentage of demand to 2031-32. The DSP forecast assumed that 25% of the PDRS target will be delivered through energy efficiency and battery storage initiatives rather than through DSP, which are components accounted for separately in AEMO's forecasts.

Figure 7 shows the PDRS targets in megawatt values as well as the adjusted targets expected to be achieved through DSP. The scheme will, in its current design, only provide additional DSP during summer.

Figure 7 PDRS target and DSP applied in forecasts for the summer period in New South Wales, 2022-23 to 2031-32 (MW)



2.2.9 Generator auxiliary load

Generator auxiliaries, which are used in the calculation of the EST, have been updated to reflect the adjusted generator availability. The generator auxiliary load forecast for all years after 2022-23 was calculated using the following methodology:

- Auxiliary rates published in the 2022 FAU workbook[18] were multiplied by the available capacity for each generator, then summed.
- The summed auxiliary load was then scaled such that the calculation is consistent with the 2022 ESOO published auxiliary forecast for 2022-23.

2.2.10 Hydrogen load

Over the period assessed, hydrogen electrolyser developments are only forecast in the *Hydrogen Superpower* scenario, and potential hydrogen loads are a minor component of the EST assessment. If developed, hydrogen electrolyser operation is assumed to be flexible to minimise total costs while meeting monthly production targets, subject to an inflexible baseload component. For these future developments, AEMO assumed the load at time of maximum demand from hydrogen industries to be equivalent to that modelled in the 2022 ISP.

This assumed operation was included in the maximum demand forecasts considered in this EST assessment for the *Hydrogen Superpower* scenario. Electrolysers are not included in the EST calculation for the Central scenario.

2.3 Reserve margin

The reserve margin is calculated to cover the loss of the two largest available New South Wales generating units, shown in Table 6 for each financial year. The two largest generating units in New South Wales in 2022-23 are

[18] At https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update.

Mount Piper Power Station 1 (MP1, with 705 MW summer peak rating) and Eraring Power Station Unit 2 (ER02, with 680 MW summer peak rating).

In 2025-26, when the Eraring Power Station is expected to retire, Mount Piper Power Station 2 (MP2) becomes the second largest unit.

Table 6 Assumed reserve margin (MW, summer peak capacity)

	Unit 1	Unit 2	Reserve
2022-23	MP1	ER01	1,385
2023-24	MP1	ER01	1,385
2024-25	MP1	ER01	1,385
2025-26	MP1	MP2	1,380
2026-27	MP1	MP2	1,380
2027-28	MP1	MP2	1,380
2028-29	MP1	MP2	1,380
2029-30	MP1	MP2	1,380
2030-31	MP1	MP2	1,380
2031-32	MP1	MP2	1,380

3 Scenarios and sensitivities

In preparing a report under the EII Regulations, section 16(1), the EST monitor must take into account each scenario and the sensitivities relating to each scenario, as specified in the most recent statement of opportunities, to the extent they relate to New South Wales.

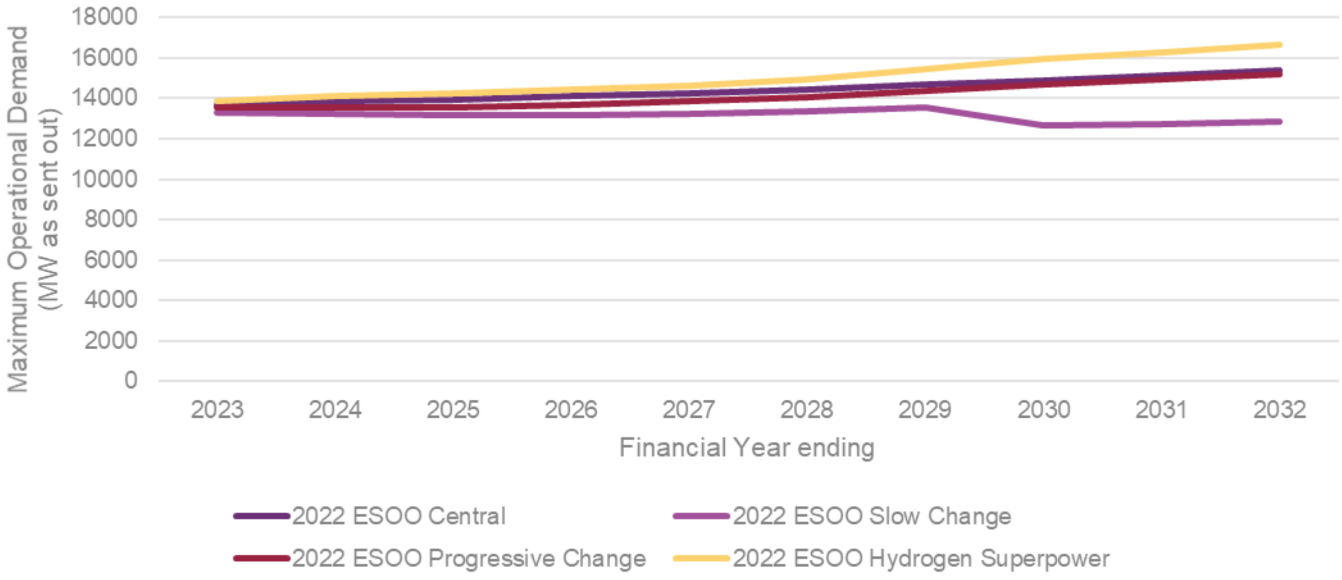
As such, AEMO has assessed the EST against each scenario and relevant sensitivity used in the 2022 ESOO, as applicable to New South Wales.

Four demand scenarios were considered in the 2022 ESOO, as summarised in Table 7 below. Figure 8 shows the 2022 ESOO's 10-year maximum demand forecast for New South Wales for all four scenarios.

Table 7 Description of scenarios for the EST assessment

Scenario	Description
Slow Change	• **Challenging economic environment** following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. • Consumers continue to manage their energy needs through DER, particularly distributed PV.
Progressive Change	• **Pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.** • *Progressive Change* delivers a net zero emission economy, with a progressive build-up of momentum ending with deep cuts in emissions across the economy from the 2040s. • The 2020s would continue the current trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions. The 2030s would see commercially viable alternatives to emissions intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification in the 2040s, and nearly doubling the total capacity of the NEM. • EVs become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
Step Change **(ESOO Central scenario)**	• **Rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.** • *Step Change* moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2°C compared to pre-industrial levels. • Rather than building momentum as *Progressive Change* does, *Step Change* sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. International action follows a similar fast pace of expanded policy commitment and investment, supported by rapidly falling costs of energy production, including consumer devices. • Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification. • By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
Hydrogen Superpower	• **Strong global action and significant technological breakthroughs.** • While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, *Hydrogen Superpower* nearly quadruples energy consumption to support a NEM-connected hydrogen export industry. • The technology transforms transport and domestic manufacturing, and renewable energy exports become a significant Australian export, retaining Australia's place as a global energy resource. • While household electrification of heating and cooking appliances still occurs, many households with gas connections will progressively switch to a hydrogen-gas blend before appliance upgrades achieve 100% hydrogen use.

Figure 8 New South Wales 10% POE maximum summer demand forecast, operational sent out, in MW across scenarios



In addition to the above scenarios, the EST has also been assessed under a range of sensitivities, which were either included in the 2022 ESOO or requested by the New South Wales Office of Energy and Climate Change. These have been assessed under the demand forecasts associated with the Central scenario:

- *Anticipated and actionable* – this sensitivity includes generation and storage that is committed, committed* or anticipated, and transmission that is anticipated or actionable in the 2022 ISP. It was included in the 2022 ESOO.
- *Anticipated with Snowy 2.0 delay* – this sensitivity includes generation and transmission that is committed, committed*, anticipated or actionable, and also places a two-year delay on completion of the Snowy 2.0 project. It was included in the 2022 ESOO.
- *Anticipated with HumeLink delay* – this sensitivity includes generation and transmission that is committed, committed*, anticipated or actionable, and also places a two-year delay on completion of the HumeLink transmission project. It was not included in the 2022 ESOO and is an additional sensitivity for the EST report.
- *Anticipated with demand side solution delays* – this sensitivity includes generation and transmission that is committed, committed*, anticipated or actionable, but excludes aggregated DER forecasts that are not yet committed, such as Vehicle to Grid (V2G) and Virtual Power Plants (VPP), as well as growth in DSP including the Peak Demand Reduction Scheme. The purpose of this sensitivity is to demonstrate the impact of these demand side solutions on the EST assessment. It was included in the 2022 ESOO.
- *Anticipated with Hunter Transmission Delay* – this sensitivity includes generation and transmission that is committed, committed*, anticipated or actionable. It applies a two-year delay to the Hunter Transmission Project (so that it is operating from 2029-30) and moves the closure of Vales Point one year earlier (so that it is closed in 2028-29). It was not included in the 2022 ESOO and is an additional sensitivity for the EST report.

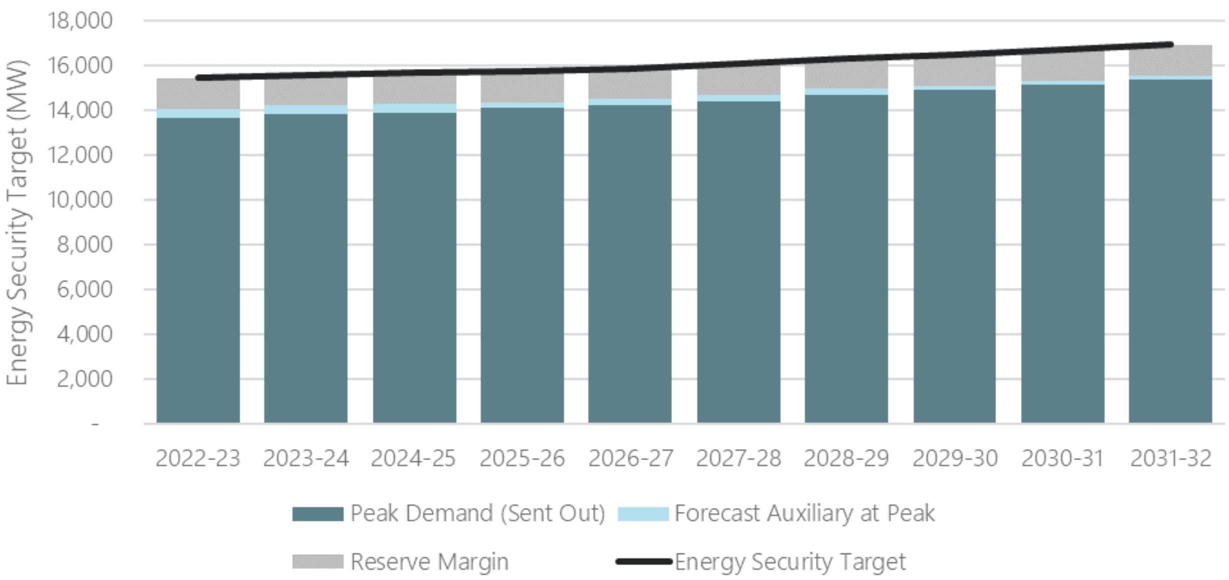
4 EST assessment

The EST assessment has been conducted for all scenarios and sensitivities described in Section 3.

4.1 Central scenario

In the Central scenario, 10% POE maximum demand is forecast to grow with an increase in residential usage and an increase in the rate of electrification (fuel switching from other fuels to electricity), with growth somewhat offset by a forecast increase in distributed PV. Auxiliaries at time of peak are forecast to decline, following the expected exit of numerous coal-fired generators. The reserve margin is forecast to reduce from 1,385 MW to 1,380 MW over the horizon, as shown in Table 6. Collectively these components sum to the EST, as shown in Figure 9.

Figure 9 Central scenario forecast, EST components



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

- Between summer 2021-22 and 2022-23, about 263 MW of additional variable renewable energy generation is expected to become operational.
- The Avonlie Solar Farm, New England Solar Farm, Rye Park Wind Farm, and Wollar Solar Farm are assumed to connect in 2023-24.
- The Waratah Super Battery is considered committed and is assumed to operate as transmission support for NSW SIPS from 2025-26 to 2029-30 and then operate as a battery.
- Facilities supported by the New South Wales Government are included as committed: the Sapphire Battery facility (from 2023-24), New England battery (from 2023-24) and the Darlington Point Battery Energy Storage System (BESS) project (from 2024-25).
- Based on information provided by Snowy Hydro, the Snowy 2.0 project retains its previously advised commissioning schedule of between 2025-26 and 2026-27.

- Energy Australia's 320 MW gas generator Tallawarra B is considered committed*, operational from 2023-24.
- The remaining three units of Liddell are scheduled to retire in April 2023, followed by the 2,880 MW Eraring Power Station in August 2025 and Vales Point B Power Station in 2029.

Figure 10 shows the projected assessment of the EST for this Central scenario considering the changes to existing and committed supply. A target breach is forecast from 2025-26 onwards, following the exit of Eraring Power Station, consistent with the 2022 ESOO which forecast an emerging reliability gap from 2025-26 in New South Wales.

Figure 10 Central scenario, assessment of the EST with existing and committed supply

Key considerations in, and observations from, the assessment are:

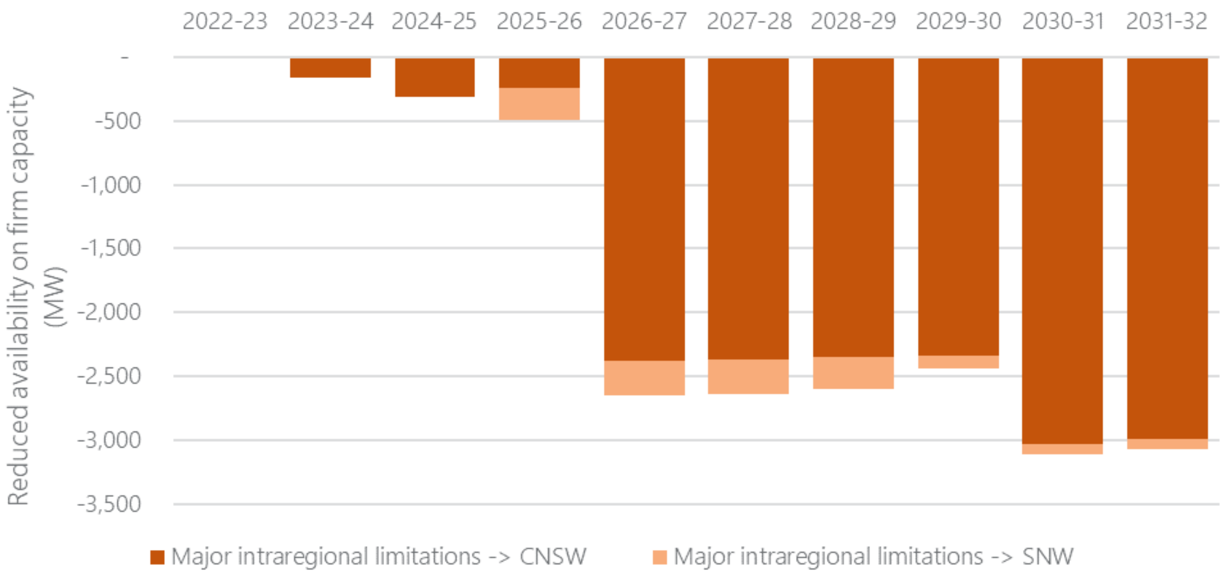
- Existing firm capacity is forecast to be sufficient to meet the EST at the start of the horizon.
- In 2023-24, when the Liddell Power Station retires, the loss of capacity is forecast to be offset by the commitment of new scheduled generation within the SNW sub-region, including Kurri Kurri and Tallawarra B power stations.
- Committed interconnector import capacity is expected to become available over the horizon from VNI Minor (from 2022-23), QNI Minor (from 2023-24), and Project EnergyConnect (from 2026-27). However, forecast major constraints on intra-regional transmission infrastructure between the outer and inner sub-regions of New South Wales, as shown below in Figure 11, are expected to constrain this proposed capacity from being fully available to consumers in the CNSW and SNW sub-regions during peak demand periods. As such, this capacity is partially discounted over the EST horizon.
- Proposed semi-scheduled and scheduled generation capacity is expected to become available in the SNSW sub-region, including the Snowy 2.0 and Darlington Point Battery Energy Storage System (BESS) projects.

However, forecast major constraints on intra-regional transmission infrastructure between the outer and inner sub-regions of New South Wales are expected to constrain this proposed capacity from being fully available to consumers in the CNSW and SNW sub-regions during peak demand periods. As such, this proposed capacity is partially discounted over the entire horizon.

- A target breach is forecast in 2025-26 and 2026-27 then from 2029-30 onwards, when scheduled generators (Eraring then Vales Point power stations) in the SNW sub-region retire. At this point, firm capacity from outside this sub-region would be required to meet demand in peak demand periods but cannot be made available to the majority of New South Wales customers due to forecast constraints on intra-regional transmission infrastructure.
- While EST breaches are forecast from 2025-26 when considering only committed projects, additional generation, storage and transmission projects are anticipated or are deemed actionable in the 2022 *Integrated System Plan* (ISP)[19]. A sensitivity showing the impact of these projects is shown in Section 4.2.4.
- Other potential solutions to mitigate the projected target breach include:
  - The commitment of new generation or storage capacity in the SNW region.
  - The commitment of new generation or storage capacity in sub-regions further away from SNW, with appropriate transmission investments.
  - The commitment of new DSP.
  - The commitment of new inter-connector capacity, only if supported with appropriate intra-regional transmission investments.

Figure 11 shows the projected reduction in generation, storage, and interconnector firm capacity due to these major constraints on intra-regional transmission infrastructure in this assessment.

Figure 11 Central scenario, estimated impact of transmission limits on firm capacity



[19] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

4.2 Alternative scenarios and sensitivities

4.2.1 Slow change

The *Slow Change* scenario varies from the Central scenario primarily due to differences in demand, including potential large industrial load closures, and lower DER orchestration assumptions regarding VPP and V2G developments. The assessment is shown in Figure 12. The lower demand assumptions result in no breach of the EST until 2029-30.

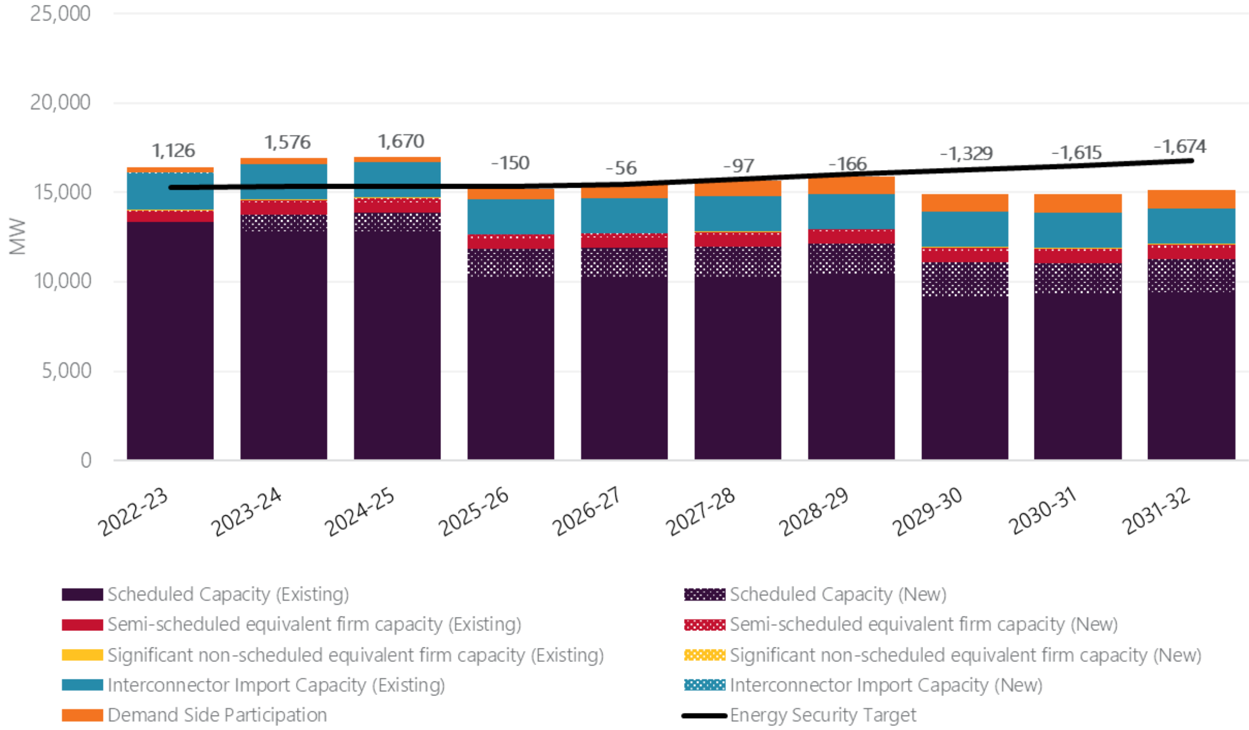
Figure 12 *Slow Change* scenario, assessment of the EST

4.2.2 Progressive change

The EST assessment for the *Progressive Change* scenario is shown in Figure 13. The scenario features marginally lower demand than the Central scenario, although not as low as *Slow Change*. The breach is smaller than the Central case in 2025-26 and 2026-27, and is larger for the remainder of the forecast horizon.

Key observations and solutions to mitigate the forecast target breach remain the same as the Central scenario, however the larger size of the breach in the later years indicates an increased need for additional firm capacity in this scenario.

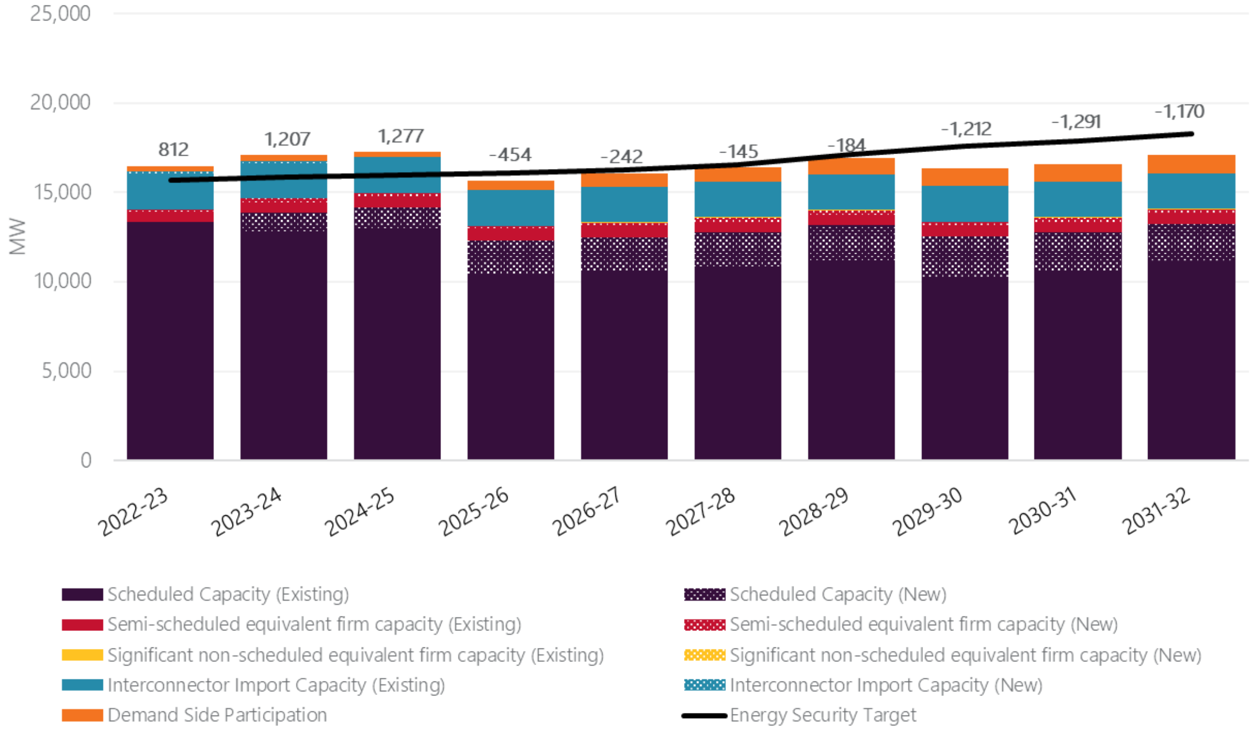
Figure 13 ***Progressive Change* scenario, assessment of the EST**



4.2.3 Hydrogen Superpower

The EST assessment for the *Hydrogen Superpower* scenario is shown in Figure 14. Higher demand in this scenario leads to a larger breach compared to the Central scenario, indicating an increased need for additional firm capacity in this scenario. While this scenario has the highest demand, it does not have the largest breach due to the levels of distributed aggregated storage also assumed in this scenario.

Figure 14 *Hydrogen Superpower* scenario, assessment of the EST



4.2.4 *Anticipated and actionable* (sensitivity on the Central scenario)

The EST assessment under the *Anticipated and actionable* sensitivity is shown in Figure 15. Under this sensitivity, the EST is still breached in 2025-26 and 2026-27 but then there are sufficient new generation and transmission developments from 2027-28 onwards for there to be an EST surplus.

Additional projects that are included as anticipated or actionable but not committed include:

- The Quorn Park, Walla Walla and Yanco solar farms (all operating from 2024-25).
- The Orana BESS (from 2026-27).
- The Hunter Transmission Project (from 2027-28), New England Expansion (from 2027-28) and HumeLink (from 2026-27) transmission projects[20].

While EST breaches are forecast from 2025-26 when considering only committed projects, additional generation, storage and transmission projects are anticipated or are deemed actionable in the 2022 ISP[21]. These projects – which include the Hunter Transmission Project and the HumeLink transmission project – are forecast to significantly increase intra-regional transfer limits into the Sydney-Newcastle-Wollongong sub-region, thereby allowing already committed firm capacity to be available to New South Wales electricity customers during peak demand periods. Once these projects are also considered, all EST breaches from 2029-30 are resolved.

Further, the New South Wales Minister for Energy has directed the Consumer Trustee to run a new tender[22], which anticipates at least 350 MW of firming infrastructure by 2025-26 located in the Sydney-Newcastle-

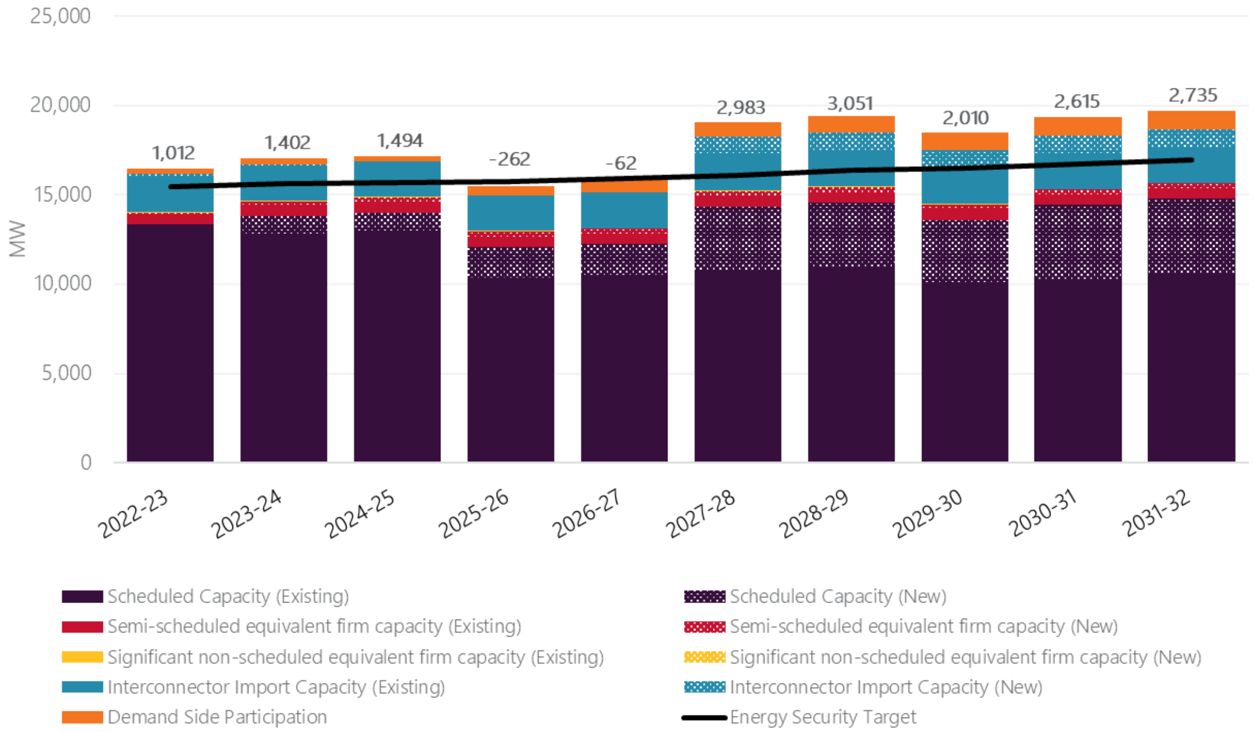
[20] Note the anticipated Central West Orana transmission project is not relevant to the EST calculation as it is does not cross sub-regional boundaries.

[21] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[22] See https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap/energy-security-target-monitor.

Wollongong sub-region that is not considered in this sensitivity. Should the firming infrastructure deliver the firm capacity anticipated, all EST breaches over the 10-year EST assessment horizon are projected to be resolved.

Figure 15 ***Anticipated and actionable*, assessment of the EST**



From 2029-30, the forecast EST surpluses are highly dependent on simplified factors that may not adequately align with the true risks to New South Wales energy consumers that would be represented in a reliability assessment such as the ESOO. AEMO recommends further investigation of these factors in future EST assessments:

- Inter-regional transfer capacity, and whether generation in other regions is available at times when required to support New South Wales demand centres.
- Energy limited generation and short duration storage, and whether the energy limits and storage duration are likely to impact availability during periods of New South Wales supply scarcity.

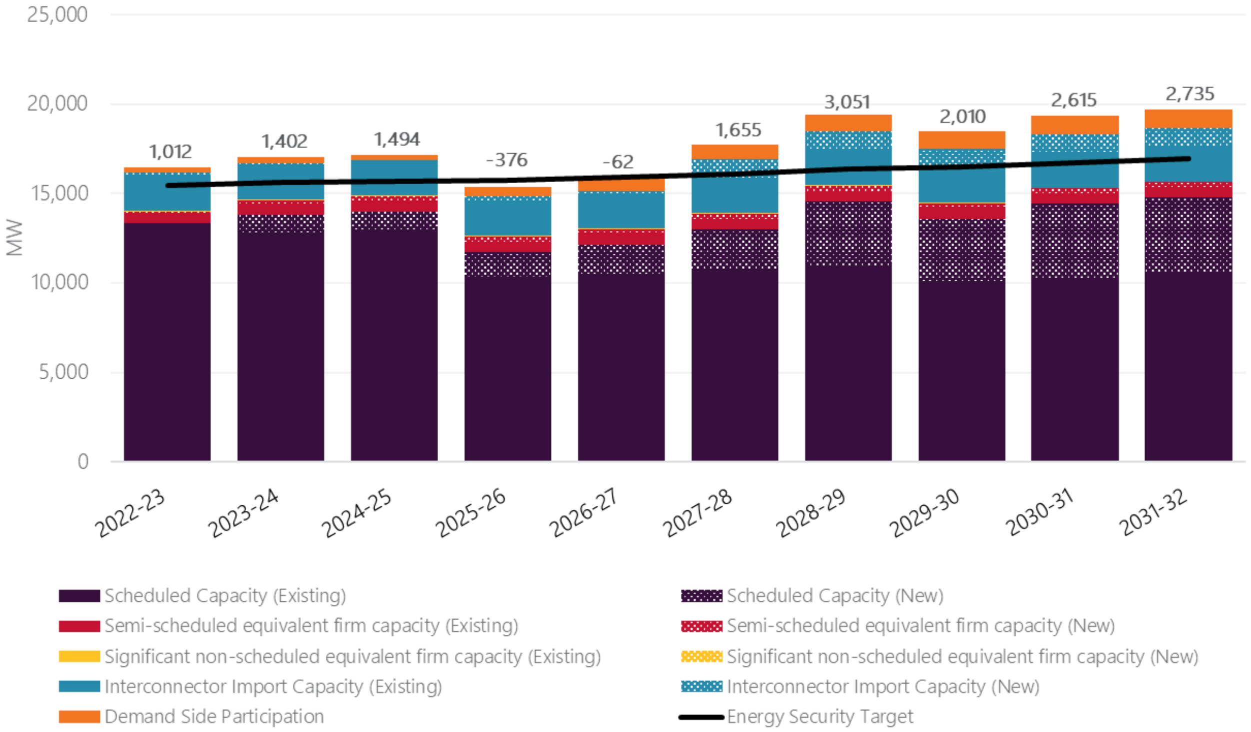
4.2.5 *Anticipated with Snowy 2.0 delay* (sensitivity on the Central scenario)

The Snowy 2.0 development is a key storage development presently committed and under construction. It will utilise improved connectivity with New South Wales consumers with the development of new transmission investments, particularly the HumeLink and VNI West actionable ISP projects, when constructed. Consistent with the 2022 ESOO sensitivity, without the development of HumeLink, the project is not able to deliver a reliability benefit in the Central scenario, and likewise does not reduce reliability if it were delayed in this case.

Recent media speculation has suggested a likely delay to the project, however the project proponent, Snowy Hydro, provided unchanged advice in the 2022 ESOO to that provided in the 2021 ESOO regarding the intended commissioning schedule of Snowy 2.0 between 2025-26 and 2026-27.

The EST assessment with an assumed two-year delay to Snowy 2.0 is shown in Figure 16. This sensitivity has similar EST deficit in 2025-26 and 2026-27 as the *Anticipated and actionable* sensitivity, because Snowy 2.0 faces transmission constraints in these years in the *Anticipated and actionable* sensitivity that are not fully resolved by the anticipated development of HumeLink, therefore its absence in the *Snowy 2.0 delay* sensitivity makes only little difference. There is a smaller surplus projected in the 2027-28 year due to the assumed delay of the Snowy 2.0 project in this sensitivity, resulting in only partial-completion in this year.

Figure 16 ***Anticipated with Snowy 2.0 delay*** **sensitivity, assessment of the EST**



4.2.6 *Anticipated with HumeLink delay* (sensitivity of the Central scenario)

The EST assessment with anticipated and actionable developments and a delay to HumeLink is shown in Figure 17. Under this sensitivity, the EST deficit in 2025-26 and 2026-27 is the same as in the *Anticipated and actionable* sensitivity, but a smaller surplus in the 2027-28 year due to the delay in HumeLink. This is because generation flows into the SNW demand centres is constrained by lack of transmission until HumeLink is commissioned in 2028-29.

Figure 17 ***Anticipated with HumeLink delay*** **sensitivity, assessment of the EST**

4.2.7 *Anticipated with demand side solution delays* (sensitivity of the Central scenario)

The EST assessment with demand side solution delays is shown in Figure 17. This sensitivity includes generation and transmission that is committed, committed*, anticipated or actionable, but excludes aggregated DER forecasts that are not yet committed, as well as growth in DSP including the Peak Demand Reduction Scheme (PDRS).

The purpose of this sensitivity is to demonstrate the impact of these demand side solutions on the EST assessment. Under this sensitivity the EST deficits in 2025-26 and 2026-27 are larger than in the *Anticipated and actionable* sensitivity, because of the absence of the PDRS and VPPs.

Figure 18 ***Anticipated with demand side solution delays*, assessment of the EST**

4.2.8 *Anticipated with Hunter Transmission Delay* (sensitivity of the Central scenario)

The EST assessment with anticipated and actionable developments and a delay to the Hunter Transmission project is shown in Figure 19. This sensitivity incorporates a 2 year delay to the Hunter Transmission project, while Vales Point power station is assumed to retire one year earlier in 2028-29. Under this sensitivity, the EST deficit in 2025-26 and 2026-27 is the same as in the *Anticipated and actionable* sensitivity, but there is a smaller surplus in the 2027-28 year and a deficit in 2028-29 due to the delay of the Hunter Transmission project and closure of Vales Point.

Figure 19 ***Anticipated with Hunter Transmission Delay*, assessment of the EST**

5 Target breach analysis

For any financial year in which AEMO considers the firm capacity will not meet the EST, and a target breach is identified, both the size of the breach (in megawatts) and the expected duration of the breach must be reported.

To estimate the duration of any target breach, AEMO compared the projected firm capacity against AEMO's 10% POE demand trace[23] developed for each scenario/sensitivity, and counted how many times operational sent out demand exceeded the following threshold in a given reference year:

$$Threshold = (Firm\ Capacity - Auxiliaries\ at\ Peak - Reserve)$$

If demand exceeded the threshold, this was considered 'an incident', meaning that reserves were below target. Under the Central scenario, there were breaches in the five financial years 2025-26, 2026-27, 2029-30, 2030-31 and 2031-32. For each of these years, the size of the EST breach and threshold are shown in Table 8.

Table 8 Size of EST breach and threshold (MW), Central scenario

Year	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
EST surplus/ breach	1,012	1,402	1,494	-262	-62	67	169	-705	-779	-612
Threshold	No breach	No breach	No breach	13,854	14,201	No breach	No breach	14,205	14,361	14,770

The below figures provide additional detail about the timing and extent of projected incidents:

- Figure 20 shows the monthly distribution of the periods that exceed the demand threshold, highlighting that reserve is expected to fall below the required margin only during summer under the assumptions made. Between 2025-26 and 2027-28 when Eraring Power Station has retired but Vales Point Power Station has not yet retired, EST target breaches are most frequently forecast between November and March.
- Figure 21 shows the projected frequency of incidents between summer and winter per year, showing that all incidents are forecast in summer, showing similar results are evident in the monthly analysis shown in Figure 18.
- Figure 22 shows the projected incident duration for summer, with longer and more severe incidents expected in 2029-30 to 2031-32.

[23] 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 20 Projected monthly distribution of incidents by forecast month and financial year, Central scenario, 2025-26 to 2031-32

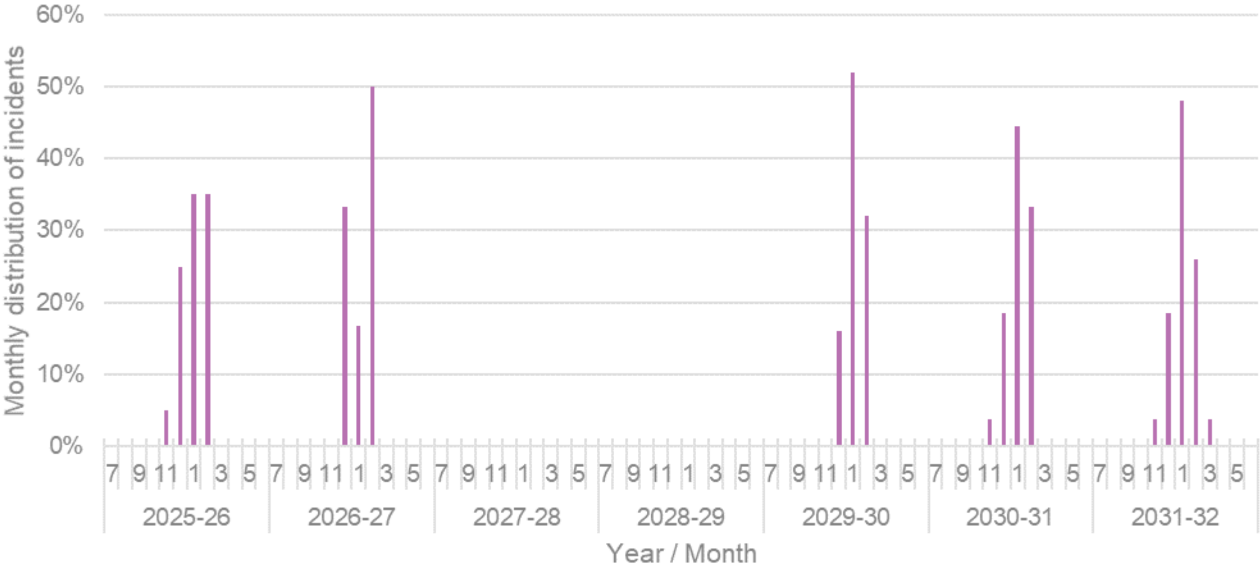
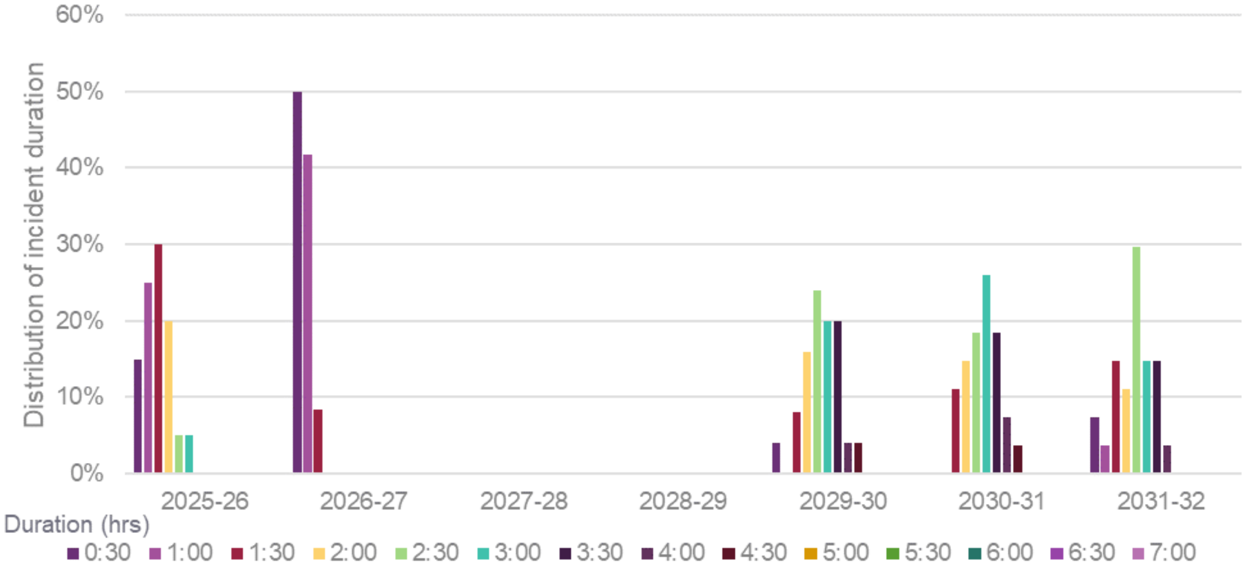


Figure 21 Projected seasonal distribution of incidents, Central scenario, 2025-26 to 2031-32

Figure 22 Projected incident duration (Summer), Central scenario, 2025-26 to 2031-32



6 EST assessment outcomes – tables

The EST assessment outcomes are shown in the following tables.

Table 9 Central scenario, EST assessment (MW)

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,753	15,903	16,085	16,361	16,493	16,722	16,965
Scheduled capacity (existing)	13,358	12,776	12,928	10,366	10,541	10,738	10,968	9,998	10,292	10,641
Scheduled capacity (new)	-	1,058	1,130	1,779	1,759	1,769	1,803	1,970	1,822	1,868
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	235	235	235	235	235	235	235	235
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity	16,468	17,014	17,182	15,490	15,840	16,152	16,530	15,788	15,944	16,353
EST surplus / deficit	1,012	1,402	1,494	-262	-62	67	169	-705	-779	-612

Table 10 *Slow Change* scenario, EST assessment (MW)

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,268	13,250	13,186	13,202	13,214	13,376	13,532	12,656	12,743	12,853
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,044	15,003	14,941	14,838	14,854	15,016	15,172	14,239	14,326	14,436
Scheduled capacity (existing)	13,338	12,696	12,761	10,080	10,114	10,137	10,162	8,869	8,871	8,894
Scheduled capacity (new)	-	1,019	1,003	1,554	1,500	1,505	1,508	1,412	1,678	1,678
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	235	235	235	235	235	235	-	-
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	94	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity	16,378	16,830	16,888	14,980	15,154	15,287	15,429	14,100	14,144	14,181
EST surplus / deficit	**1,334**	**1,827**	**1,947**	**142**	**300**	**271**	**257**	**-138**	**-182**	**-255**

Table 11 *Progressive Change* scenario, EST assessment (MW)

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,528	13,573	13,567	13,684	13,839	14,089	14,402	14,670	14,919	15,210
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,304	15,326	15,322	15,320	15,479	15,729	16,042	16,253	16,502	16,793
Scheduled capacity (existing)	13,346	12,714	12,800	10,152	10,229	10,306	10,394	9,193	9,289	9,449
Scheduled capacity (new)	-	1,058	1,068	1,673	1,655	1,681	1,724	1,911	1,767	1,826
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (New)	78	235	235	235	235	235	235	235	235	235
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	138	16	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity	16,430	16,903	16,992	15,171	15,423	15,632	15,876	14,924	14,887	15,119
Est surplus / deficit	**1,126**	**1,576**	**1,670**	**-150**	**-56**	**-97**	**-166**	**-1,329**	**-1,615**	**-1,674**

Table 12 ***Hydrogen Superpower* scenario, EST assessment (MW)**

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,889	14,114	14,243	14,464	14,642	14,931	15,476	15,983	16,307	16,686
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,665	15,867	15,998	16,100	16,282	16,571	17,116	17,566	17,890	18,269
Scheduled capacity (existing)	13,361	12,792	12,968	10,435	10,647	10,892	11,184	10,298	10,661	11,088
Scheduled capacity (new)	-	1,058	1,183	1,865	1,853	1,890	1,990	2,236	2,107	2,168
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	235	235	235	235	235	235	235	235
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	170	108	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity	16,477	17,073	17,275	15,646	16,040	16,426	16,932	16,354	16,599	17,099
Est surplus / deficit	**812**	**1,207**	**1,277**	**-454**	**-242**	**-145**	**-184**	**-1,212**	**-1,291**	**-1,170**

Table 13 ***Anticipated and actionable*** **sensitivity, EST assessment (MW)**

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,753	15,903	16,085	16,361	16,493	16,722	16,965
Scheduled capacity (existing)	13,358	12,776	12,928	10,366	10,541	10,738	10,968	9,998	10,292	10,641
Scheduled capacity (new)	-	1,058	1,075	1,724	1,704	3,600	3,600	3,600	4,130	4,130
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	291	291	291	291	291	291	291	291
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	-	-	1,030	1,030	1,030	1,030	1,030
Firm (or equivalent) capacity	16,468	17,014	17,182	15,490	15,840	19,068	19,412	18,503	19,338	19,701
Est surplus / deficit	**1,012**	**1,402**	**1,494**	**-262**	**-62**	**2,983**	**3,051**	**2,010**	**2,615**	**2,735**

Table 144 *Anticipated with delay in Snowy 2.0*, EST assessment (MW)

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	254	254	256	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,751	15,897	16,081	16,361	16,493	16,722	16,965
Scheduled capacity (existing)	13,358	12,776	12,928	10,366	10,541	10,738	10,968	9,998	10,292	10,641
Scheduled capacity (new)	-	1,058	1,075	1,378	1,602	2,268	3,600	3,600	4,130	4,130
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	291	291	291	291	291	291	291	291
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	230	96	1,030	1,030	1,030	1,030	1,030
Firm (or equivalent) capacity	16,468	17,014	17,182	15,375	15,835	17,736	19,412	18,503	19,338	19,701
Est surplus / deficit	**1,012**	**1,402**	**1,494**	**-376**	**-62**	**1,655**	**3,051**	**2,010**	**2,615**	**2,735**

Table 15 *Anticipated with delay in HumeLink*, EST assessment (MW)

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,753	15,903	16,085	16,361	16,493	16,722	16,965
Scheduled capacity (existing)	13,358	12,776	12,928	10,366	10,541	10,738	10,968	9,998	10,292	10,641
Scheduled capacity (new)	-	1,058	1,075	1,724	1,704	3,600	3,600	3,600	4,130	4,130
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	291	291	291	291	291	291	291	291
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	-	-	400	1,030	1,030	1,030	1,030
Firm (or equivalent) capacity	16,468	17,014	17,182	15,490	15,840	18,439	19,412	18,503	19,338	19,701
Est surplus / deficit	**1,012**	**1,402**	**1,494**	**-262**	**-62**	**2,354**	**3,051**	**2,010**	**2,615**	**2,735**

Table 16 ***Anticipated with demand side solution delays*, EST assessment (MW)**

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	256	260	260	260	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,753	15,903	16,085	16,361	16,493	16,722	16,965
Scheduled capacity (existing)	13,327	12,679	12,734	10,044	10,064	10,074	10,084	8,774	8,764	8,774
Scheduled capacity (new)	-	1,058	1,075	1,752	1,771	3,600	3,600	3,600	4,130	4,130
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	291	291	291	291	291	291	291	291
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	290	290	290	290	290	290	290	290	290
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	-	-	1,030	1,030	1,030	1,030	1,030
Firm (or equivalent) capacity	16,436	16,906	16,968	14,955	14,994	17,863	17,873	16,563	17,083	17,093
Est surplus / deficit	980	1,293	1,280	-798	-909	1,778	1,512	70	361	128

Table 17 ***Anticipated with Hunter Transmission Delay*****, EST assessment (MW)**

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Peak demand (sent out)	13,680	13,859	13,933	14,117	14,263	14,445	14,721	14,910	15,139	15,382
Forecast auxiliary at peak	391	368	370	256	260	260	203	203	203	203
Reserve margin	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,456	15,612	15,688	15,753	15,903	16,085	16,304	16,493	16,722	16,965
Scheduled capacity (existing)	13,358	12,776	12,928	10,366	10,541	10,738	9,648	9,998	10,292	10,641
Scheduled capacity (new)	-	1,058	1,075	1,724	1,704	1,714	1,892	3,600	4,130	4,130
Semi-scheduled equivalent firm capacity (existing)	573	573	573	573	573	573	573	573	573	573
Semi-scheduled equivalent firm capacity (new)	78	235	291	291	291	291	291	291	291	291
Significant non-scheduled equivalent firm capacity (existing)	30	30	30	30	30	30	30	30	30	30
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	290	301	310	532	726	831	945	1,006	1,017	1,030
Interconnector import capacity (existing)	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
Interconnector import capacity (new)	164	65	-	-	-	-	-	1,030	1,030	1,030
Firm (or equivalent) capacity	16,468	17,014	17,182	15,490	15,840	16,152	15,354	18,503	19,338	19,701
Est surplus / deficit	1,012	1,402	1,494	-262	-62	67	-950	2,010	2,615	2,735