AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Energy Security Target Monitor Report

October 2023

A report for the New South Wales Minister for Energy

Important notice

Purpose

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Version control

Version	Release date	Changes
1	27/10/2023	Confidential publication for the Minister for Energy
2	15/12/2023	Final publication for release

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

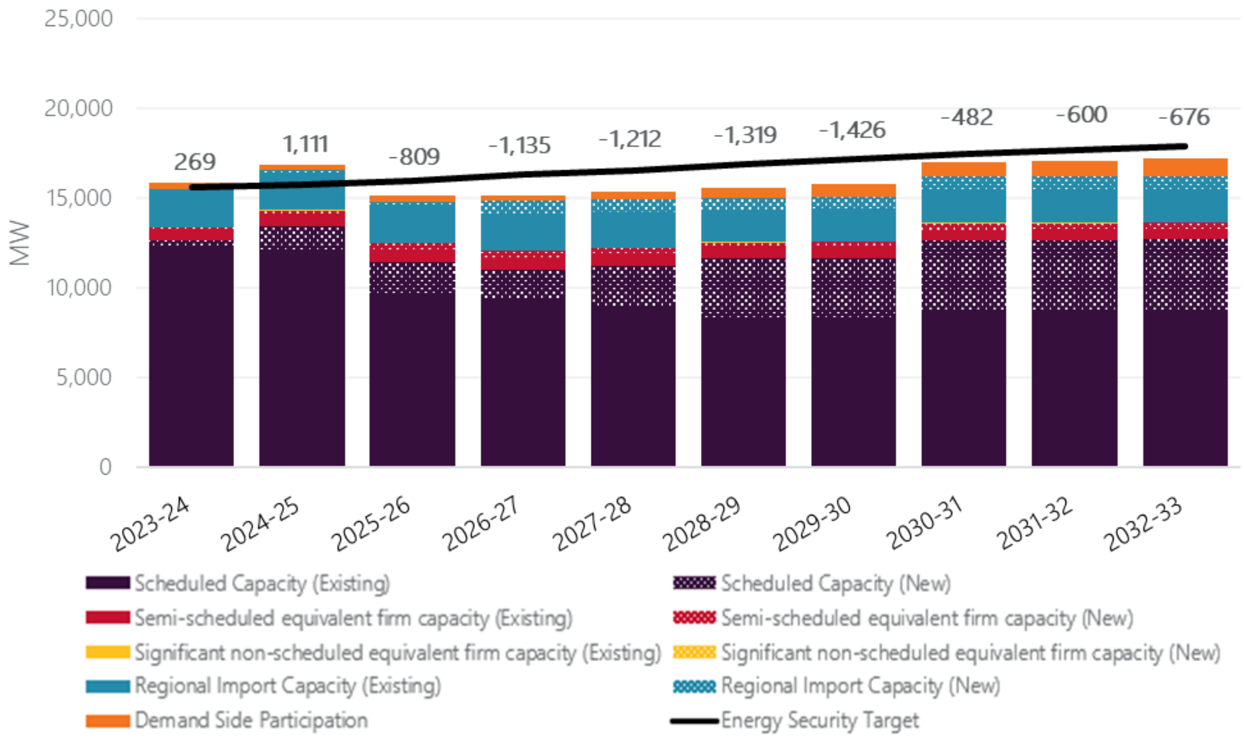
Executive summary

The Energy Security Target (EST) Monitor Report assesses whether forecast firm capacity in New South Wales is sufficient to meet the EST, which is calculated in accordance with the *Electricity Infrastructure Investment Act 2020* (NSW)[1] and the *Electricity Infrastructure Investment Regulations 2021* (NSW)[2] 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 2023 Electricity Statement of Opportunities (ESOO)[3] and inputs from the Inputs, Assumptions and Scenarios Report (IASR) and Integrated System Plan (ISP), 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 awarded Long-Term Energy Service (LTES) Agreements under the first tender of the NSW Electricity Infrastructure Roadmap are also included.

Figure 1 shows AEMO's Central scenario forecast for the 10-year EST outlook. While AEMO forecasts a surplus in 2023-24 and 2024-25, AEMO forecasts an EST breach from 2025-26 onwards following the potential early retirement of Eraring Power Station.

Figure 1 Central scenario, assessment of the EST



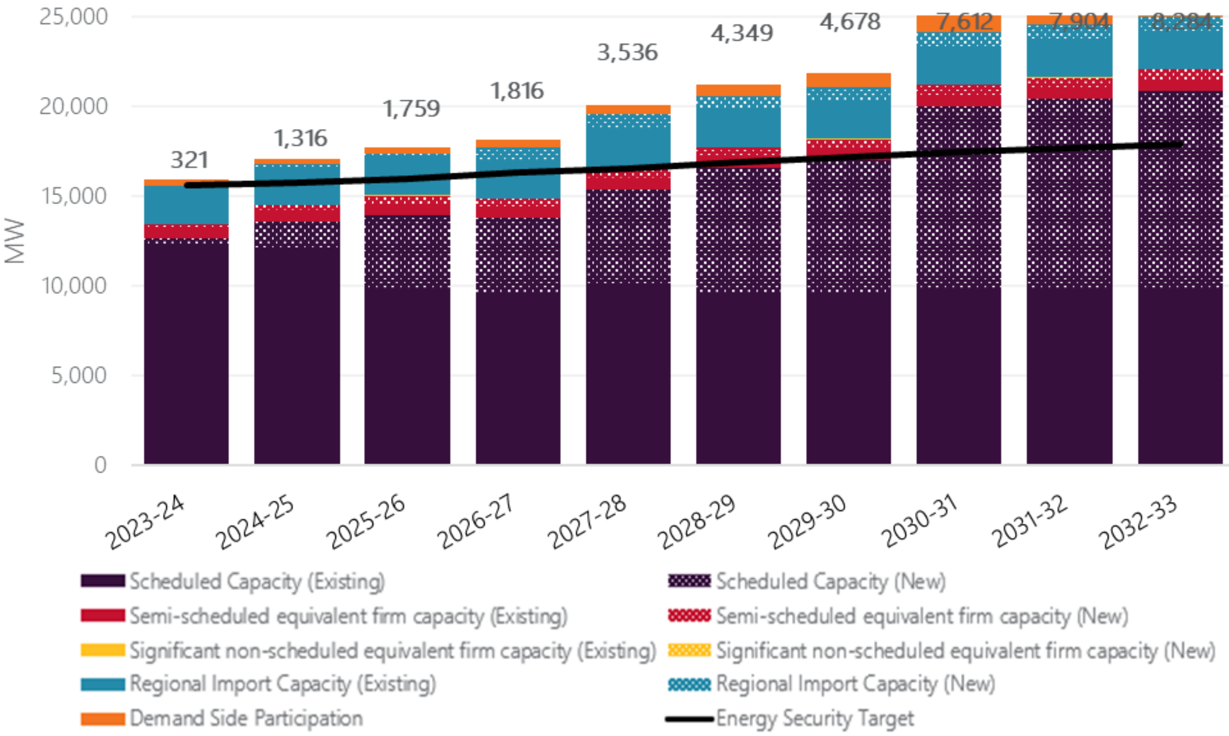
1 See https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044#pt.3.

2 See https://legislation.nsw.gov.au/view/whole/pdf/inforce/2023-10-23/sl-2021-0102.

3 At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en.

While EST breaches are forecast under the Central scenario when considering only existing and committed projects (and those that have been awarded LTES Agreements), the gaps are closed under the *Federal and state schemes* sensitivity. This sensitivity includes the impacts of transmission projects that are anticipated or are deemed actionable in the 2022 ISP[4] – the HumeLink and New England Expansion projects. It also includes anticipated generation projects and other additional projects already committed to under various federal and state government schemes and programs (notably further projects under the New South Wales Government's Infrastructure Investment Objectives [IIO] and firming infrastructure tenders).

Figure 2 ***Federal and State schemes*, assessment of the EST**



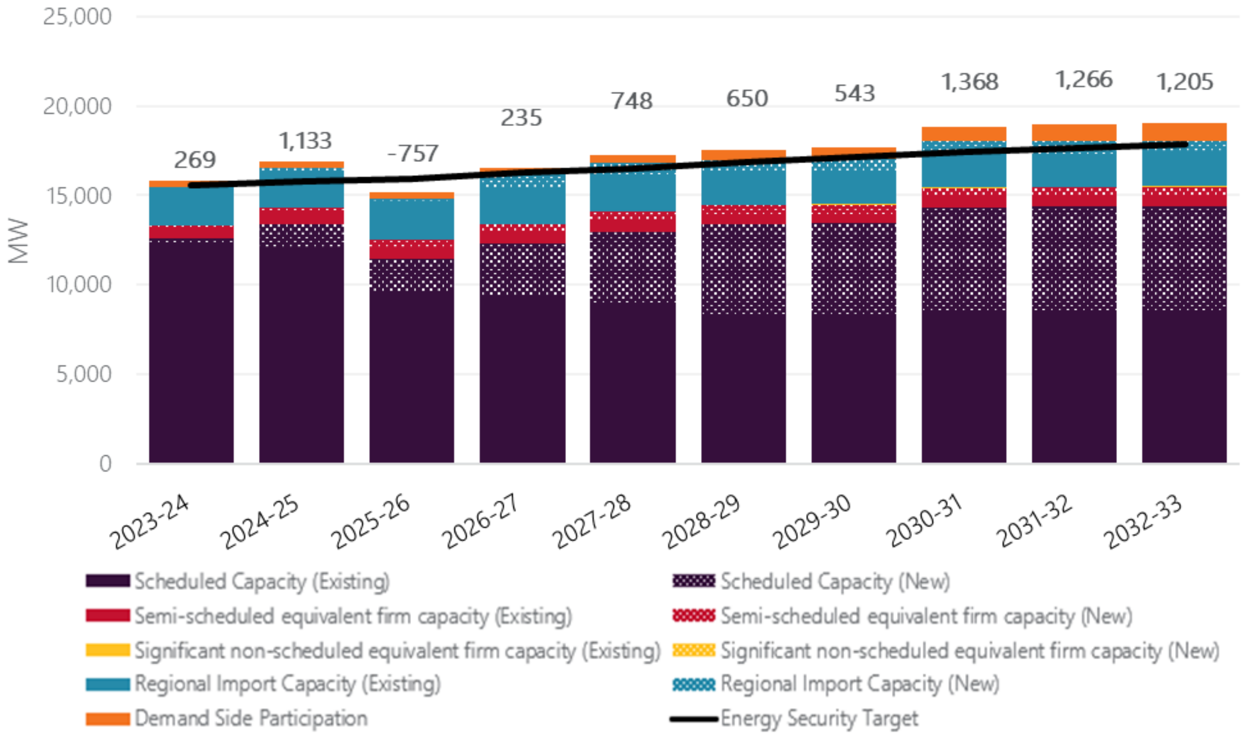
Since the 2023 ESOO was published in August 2023, AEMO Services, acting as the NSW Consumer Trustee, has announced the recipients of the firming and IIO tenders[5] 2 and 3. While the *Federal and State scheme sensitivity* demonstrates the potential impact of these schemes, only generic assumptions relating to location and technology specifications are applied consistent with the 2023 ESOO. An additional sensitivity, shown in Figure 3 and included in section 4.2.9, assesses the EST for these specific projects.

This sensitivity considers all projects in the EST Central scenario, anticipated generation projects and projects that have received LTESA's through tenders 2 and 3. Anticipated and tender recipient projects are applied with default commissioning delays. Consistent with the EST Central scenario, an EST breach is projected in 2025-26, which is resolved from 2026-27 as anticipated, and tender recipient projects become available.

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

[5] See https://aemoservices.com.au/en/tenders.

Figure 3 ***Infrastructure tenders 2 and 3 with project development delays applied, assessment of the EST***



Potential methodology review of EST assessments

In the 2022 ESTM Report, AEMO considered that EST surpluses and breaches are highly dependent on simplified factors that may not adequately align with the actual risks to consumers that are represented in a more comprehensive reliability assessment such as the ESOO. The relevant factors include assumptions regarding availability from interconnectors, perfect foresight of energy-limited capacity, and commissioning of new generators.

This 2023 ESTM Report has maintained the methodology deployed in the 2022 ESTM Report. However, as identified in the 2023 ESOO, AEMO considers that the capacity contribution shallow duration batteries may provide to customer reliability is significantly less relative to deep energy storages or other firm capacity technologies. Operational foresight of upcoming capacity requirements is imperfect, and forecasting models over-optimise stored energy by simulating the dispatch of energy-limited capacity with perfect modelling foresight.

The ESTM calculation methodology does not consider the duration of stored energy, and therefore does not reflect the potential reduced capacity available from energy storages at times of peak demand for New South Wales consumers. AEMO considers that this may over-estimate EST surpluses and/or under-estimate EST shortages.

In addition, analysis demonstrates that interconnectors, particularly the Victoria – New South Wales Interconnector (VNI) tends to be constrained at times of peak demand in New South Wales due to coincident high demand in Victoria. AEMO considers that the ESTM calculation should consider derating transmission availability from Victoria, particularly if Victoria has forecast reliability risks above the relevant reliability standard.

Another methodology change within the 2023 ESOO was the inclusion of anticipated projects in the Central scenario's reliability assessment. This 2023 ESTM Report has included only existing and committed projects in the Central EST assessment, as per 14(2)(a) of the EII Regulations. However, AEMO considers that projects that have progressed sufficiently to meet the ‘anticipated’ classification are likely to proceed to commissioning.

AEMO recommends that the EST assessment methodologies should be updated for the 2024 ESTM Report, and consider in particular those methodology changes that are considered within the ESOO reliability forecast. The New South Wales Government has also acknowledged and accepted a similar recommendation as part of the New South Wales Electricity Supply and Reliability Check Up process, conducted in September 2023[6].

[6] At https://www.energy.nsw.gov.au/sites/default/files/2023-09/Electricity_Supply_and_Reliability_CheckUp_NSW_Government_Response_September_2023.pdf

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1 Introduction

The Energy Security Target (EST) Monitor Report assesses whether forecast firm capacity in New South Wales is sufficient to meet the EST, which is calculated in accordance with the *Electricity Infrastructure Investment Act 2020* (NSW)[7] (the EII Act) and the *Electricity Infrastructure Investment Regulations 2021* (NSW)[8] (the EII Regulations) 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 and the EII Regulations. 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 EII Regulations.

For the purposes of section 14(2) 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.

Changes since the 2023 Electricity Statement of Opportunities

Since the 2023 ESOO was published in August 2023, AEMO Services, acting as the NSW Consumer Trustee, has announced the recipients of the firming and IIO tenders[9] 2 and 3. While the 2023 ESOO included a *Federal and State scheme sensitivity* that demonstrated the potential impact of these schemes, only generic assumptions relating to location and technology specifications are applied consistent with the 2023 ESOO. An additional sensitivity is included in section 4.2.9 that assesses the EST of these specific projects. This sensitivity also considers the development of projects classified by AEMO as 'anticipated'. All other inputs and assumptions align with the EST Central scenario.

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

[8] See https://www.legislation.nsw.gov.au/view/whole/pdf/inforce/2023-10-22/sl-2021-0102.

[9] See https://aemoservices.com.au/en/tenders.

2 Inputs and assumptions

For this EST assessment, AEMO has adopted inputs and assumptions used to produce the 2023 Electricity Statement of Opportunities (ESOO)[10] and other relevant assumptions from AEMO's 2023 Inputs, Assumptions and Scenarios Report (IASR)[11], 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 clause 13 of the EII Regulations, 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 2023 ESOO. Consistent with the 2023 ESOO, AEMO considers the *Step Change* scenario to be most likely, and therefore the Central scenario.
- Included the forecast of generating unit auxiliaries based on that forecast by AEMO in the 2023 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 2023 ESOO.

Maximum operational demand means the highest level of electricity drawn from the grid in any 30-minute period in a financial year. In the 2023 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 indicates that the forecast is expected to be exceeded once in every 10 years.

Figure 4 explains AEMO's demand definitions. Further detail is provided in AEMO's 2023 ESOO[12].

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)[13], are considered committed developments, and are included in AEMO's demand forecasts. As such, they are captured in this EST assessment.

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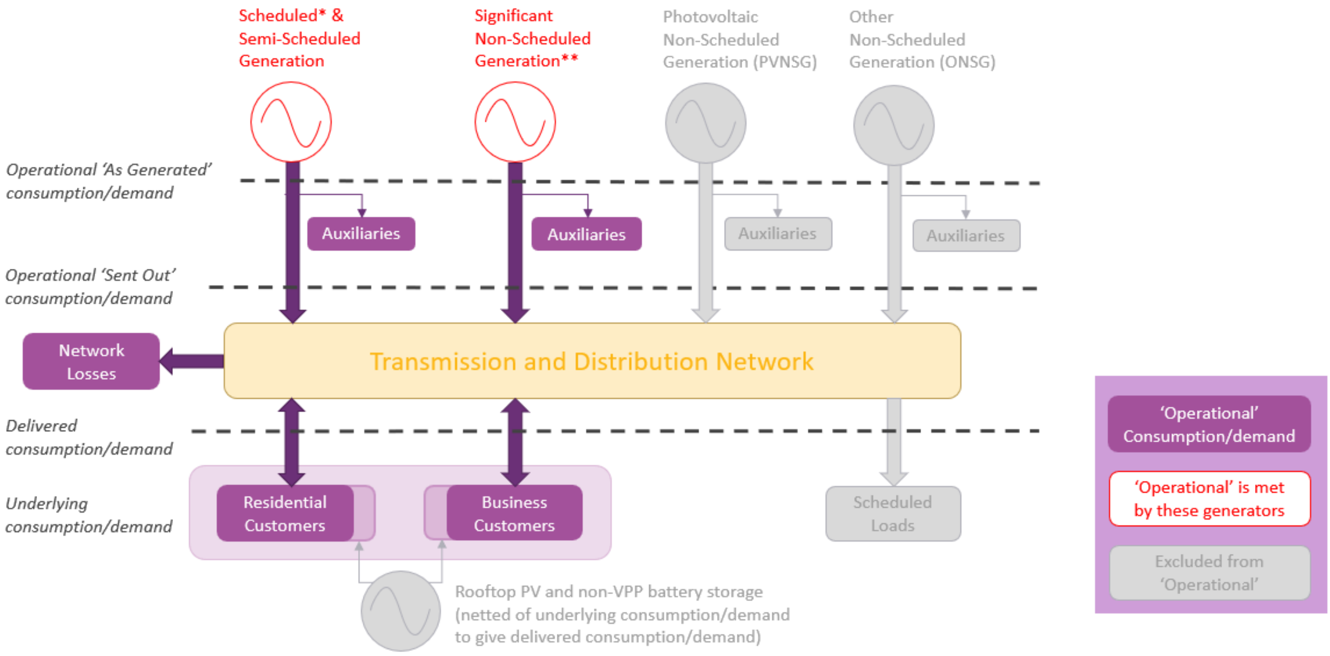
[10] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en.

[11] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[12] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en.

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

Figure 4 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 Regulations, in clauses 14 and 15, provide that the calculation of firm capacity for the EST includes scheduled (including storage), semi-scheduled, and significant non-scheduled generation from existing and new sources, which is consistent with the sources of generation that AEMO defines when referring to operational demand (see Figure 4). Firm capacity for an EST forecast year should also account for forecast interconnector capacity, demand response, and demand side participation (DSP), and is that which is considered available during peak demand periods.

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 September 2023 Generation Information publication[14]. 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 Regulations, in clause 15(2), stipulate 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

[14] 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 were based on a 25% POE calculation; that is, three times out of four, 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 each of the last three summers (2020-21, 2021-22 and 2022-23). Ten days were chosen for each year for the 2023 EST assessment to ensure a reasonable sample size of high demand days. For this purpose, summer was defined as the period from December to February.
2. Observed aggregate semi-scheduled and significant non-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 25th percentile of these observed aggregate capacity factors (meaning that 75% of observed aggregate capacity factors exceeded this percentile).

Figure 5 shows the calculated peak contribution factors derived using the above method for the typical times of peak demand across the collection of peak demand days. Factors derived for solar trend downwards from 5.00 pm, showing that solar generation is unlikely later in the evening as sunset approaches. On the other hand, factors derived for wind technologies trend upwards between 5.00 pm and 8.00 pm, ranging from 4% to 23%.

Figure 5 25th percentile capacity factors for top 10 summer days

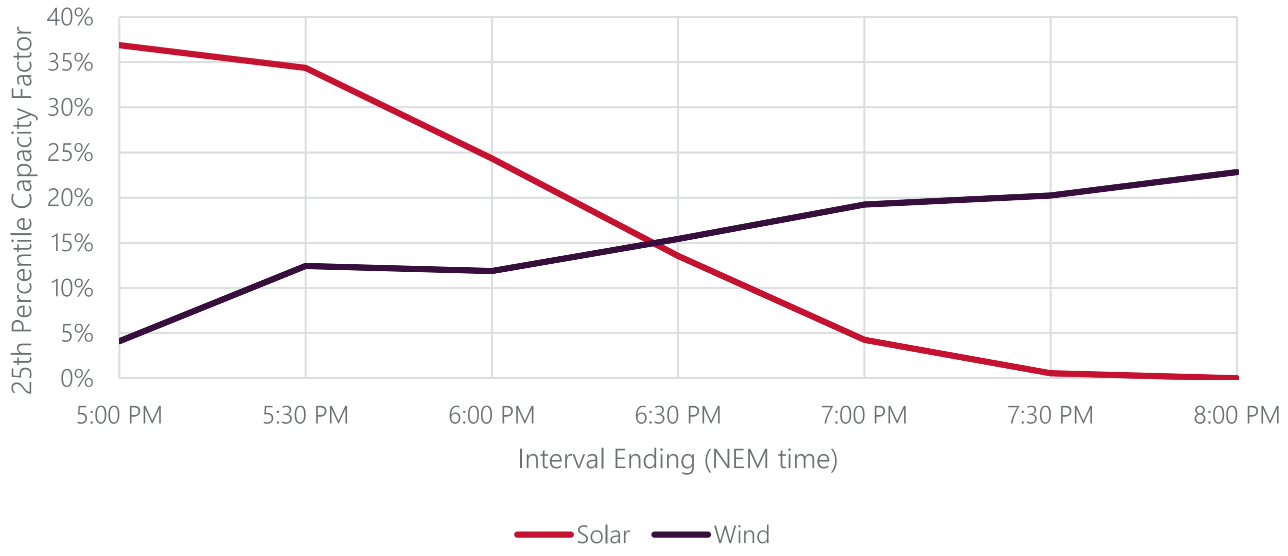
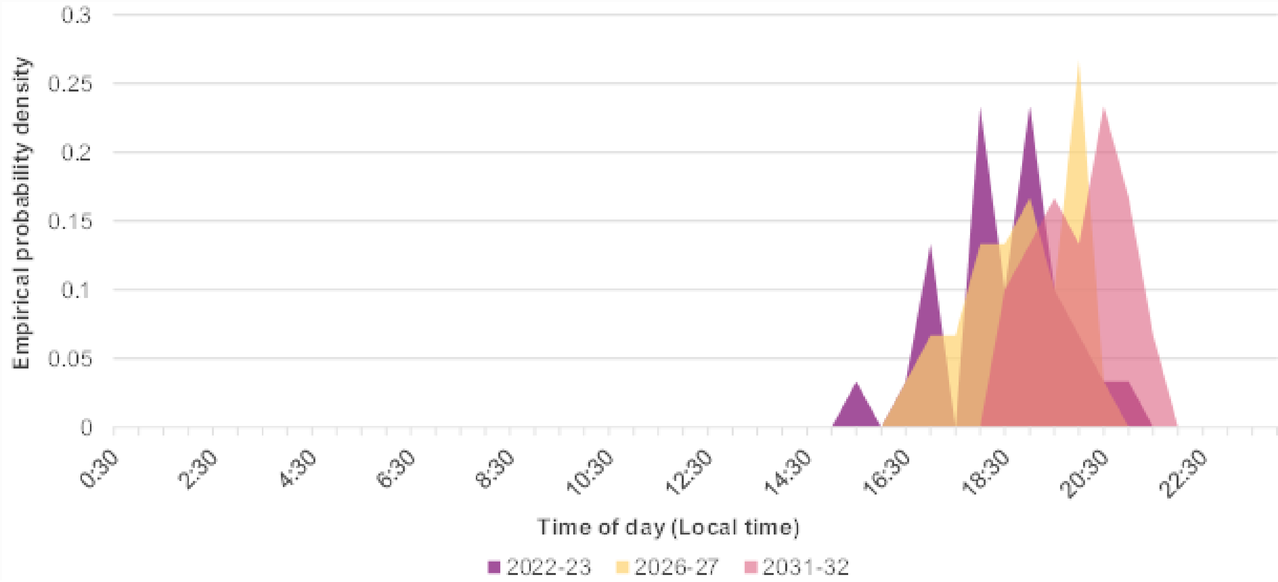


Figure 6 shows the probability distribution of forecast maximum demand for New South Wales summer in local time. The timing of when maximum demand will occur in future years remains a key uncertainty, influenced by the evolution of consumer demand trends including the contribution to peak demand from consumers' own consumer energy resources (CER).

For the purposes of the 2023 EST assessment, AEMO selected the 6:30 pm National Electricity Market (NEM) time (7:30 pm local daylight savings time) interval to represent the maximum demand interval for the entire forecast horizon. This has not changed since the 2022 assessment.

Figure 6 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 2023 EST Monitor Report was estimated to be 15.4% for wind and 13.5% for solar. These factors differ from those calculated in the 2022 EST Monitor Report of 17.9% for wind and 10.7% for solar.

These capacity factors were applied to the Summer Typical capacity from the September 2023 Generation Information publication[15] 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 typically refer to wind and solar non-scheduled generators with a capacity greater than or equal to 30 megawatts (MW)[16]. Table 1 outlines the New South Wales generators that are defined in this category.

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

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

[16] 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.

The available firm capacity of significant non-scheduled generators was calculated using the peak contribution factors of the relevant semi-scheduled and non-scheduled technology as outlined in the above section. A single contribution factor was calculated for semi-scheduled and non-scheduled generators, given that contribution factor is expected to vary by technology type rather than registration category.

2.2.4 Generator closures

Expected closure years for all existing generators were taken from the September 2023 Generating unit expected closure year and Generation Information publications[17]. Following the recent closure of the Liddell Power Station, the Eraring Power Station is now the only closure in New South Wales in the forecast period. Its expected closure is in August 2025 and it was modelled to close after the summer of 2024-25.

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 at times of peak demand 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*'[18] in the September 2023 Generation Information publication. These projects are included with delays applied to the Full Commercial Use Date (FCUD) provided by the project proponent, to reflect observed delays in project commissioning. AEMO considers that these delays are prudent and will better reflect the timing that the projects will be available to NSW electricity customers, per Section 14(2) of the EII Regulations. More information on this approach is described in the 2023 ESOO.
2. Projects that will be constructed and operated under a Long-Term Energy Service (LTES) Agreement. The following projects in Table 2 have been awarded an LTES Agreement during the round one tender for generation and long duration storage infrastructure in New South Wales[19].

Table 2 Projects awarded an LTES Agreement

Project	Expected completion date	Nameplate capacity (MW)
Goldwind Australia's Coppabella Wind Farm	In advance of summer 2025-26	275
ACEN Australia's New England Solar Farm	In advance of summer 2025-26	720
ACEN Australia's Stubbo Solar Farm[20]	In advance of summer 2025-26	400
RWE Renewables Australia's Limondale BESS	In advance of summer 2025-26	50

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

[18] 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.

[19] At https://aemoservices.com.au/tenders/tender-round-1.

[20] Stubbo Solar Farm is considered Committed and would be included in the assessment based on AEMO's Generation Information.

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 3 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.

Table 3 Additional projects that will be constructed under New South Wales Government or Commonwealth Government funding programs

Project	Expected completion date	Nameplate capacity (MW)	Included in EST assessment
Waratah Super Battery	To operate between 2025-26 and 2029-30	150 MW during operation of System Integrity Protection Scheme (SIPS) (which assumes 910 MW) then 850 MW as commercial battery	Yes
CWP Renewables' Sapphire Battery Facility	In advance of 2023-24 summer, with delay applied to 2024-25 summer	30	Yes
UPC/AC Renewables Australia's New England Solar Farm Battery	In advance of 2024-25 summer, with delay applied to 2025-26 summer	200	Yes
Darlington Point Battery Energy Storage System (BESS)	90 MW in advance of 2023-24 summer. Remaining 60 MW in advance of 2023-24 summer with delay applied to 2024-25 summer.	150	Yes
AGL's Liddell Big Battery	In advance of 2025-26 summer	250	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 derived from https://energy.nsw.gov.au/renewables/clean-energy-initiatives/emerging-energy-program, and https://arena.gov.au/news/arena-backs-eight-grid-scale-batteries-worth-2-7-billion/.

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 2023 IASR and is summarised in Table 4.

Table 4 Import capabilities between sub-regions at peak demand

Interconnector	New South Wales import capability (MW)
NNSW – SQ ("Terranora")	130
NNSW – SQ ("QNI")	1,205
VIC – SNSW ("VNI")	870
SNSW – SA ("Project EnergyConnect")	800 (from 2026-27 once Project EnergyConnect fully commissioned)

2.2.7 Major transmission limits

Major intra-regional transmission limits can reduce the amount of electricity available to New South Wales customers from generation, storage, and interconnector capacity. Consistent with clause 15(4) of the EII Regulations, 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 simplified, deterministic calculation that is relatively easy to understand, a sub-regional representation of the New South Wales transmission network was used to estimate the major network constraints as defined in the 2023 IASR[21].

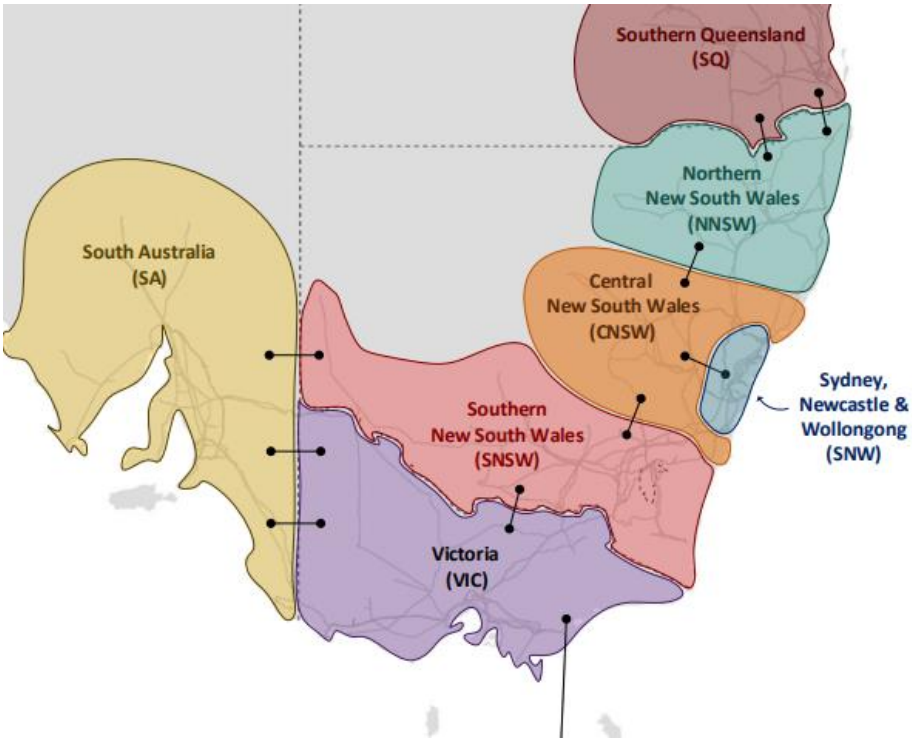
The key New South Wales sub-regions are highlighted in Figure 7. The following intra-regional assessments were conducted to identify major network constraints:

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.
3. **Northern New South Wales, Central New South Wales and SNW (NNSW + CNSW + SNW)** – this identifies any major transmission limits that may constrain supply from Southern New South Wales sub-regions into the Central sub-region.

To test whether these major transmission limits impact the EST, AEMO first assessed the EST against each relevant sub-region separately. AEMO has 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 single largest unit in the sub-region is unavailable. In the 2022 EST assessment, this was assessed against the largest two units in the sub-region being unavailable; AEMO considered this to be overly onerous on a sub-regional level, and not in keeping with the intention of the regional requirement of the regulations. The failure of the single largest unit in each sub-region still takes into account the more likely risk of a single unit failure in each sub-region rather than the more unlikely event of co-incident failures of two units in each sub-region. The regional assessment is still based on the event that the largest two units are unavailable.

[21] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

Figure 7 Sub-regional model as documented in the IASR



Where the sub-regional reserve estimates result in a target surplus/breach that is lower/higher than the whole of the New South Wales EST surplus/breach, the difference was assessed as the impact of the major intra-regional transmission limit. If major intra-regional transmission limits were identified, all capacities were discounted evenly until the limitations evidenced by the sub-regional assessment were incorporated.

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[22], as summarised in Table 5.
- Auxiliaries were assumed as a ratio of maximum potential sub-regional aggregate auxiliaries to the maximum potential regional aggregate auxiliaries[23].
- Reserves were calculated as the largest generating unit in the sub-region, or the largest two generating units in the state-wide assessment.
- Firm and equivalent firm capacity as available in the sub-region.
- Intra-regional transmission import capabilities between sub-regions, as summarised in Table 6.

[22] As per the 2022 ESTM Report, the 2011 reference year was chosen. Annual maximums were taken from these published 10% POE traces and were scaled to the traces published in the 2023 ESOO.

[23] 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 5 Assumed sub-regional 10% POE maximum operational demand Central forecasts (MW, as generated)

	All NSW	CNSW + SNW	SNW	NNSW + CNSW + SNW
2023-24	13,822	11,936	10,389	12,885
2024-25	14,034	12,199	10,728	13,126
2025-26	14,284	12,413	10,880	13,354
2026-27	14,637	12,713	11,087	13,675
2027-28	14,940	12,970	11,276	13,951
2028-29	15,318	13,210	11,320	14,252
2029-30	15,631	13,477	11,541	14,542
2030-31	15,909	13,787	11,947	14,842
2031-32	16,148	13,993	12,132	15,071
2032-33	16,344	14,156	12,296	15,257

Table 6 Import capabilities between sub-regions at peak demand

Intra-regional limit	Intra-regional import capability (MW)
SNSW → CNSW	2,700 + Shoalhaven generation (plus an additional 910 MW 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 910 MW from either SNSW->CNSW or NNSW->CNSW between 2025-26 and 2029-30 due to the operation of the NSW SIPS)
CNSW → SNW	4,490 + 0.12 * Eraring generation (plus an additional 910 MW between 2025-26 and 2029-30 due to the operation of the NSW SIPS, and an additional 5,000 MW from 2027-28 due to the Hunter Transmission Project)
SNSW → SNW	2,540 – 0.51 * (Tallawarra + Tallawarra B generation) (plus an additional 250 MW between 2025-26 and 2029-30 due to the operation of the NSW SIPS)

Source: https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

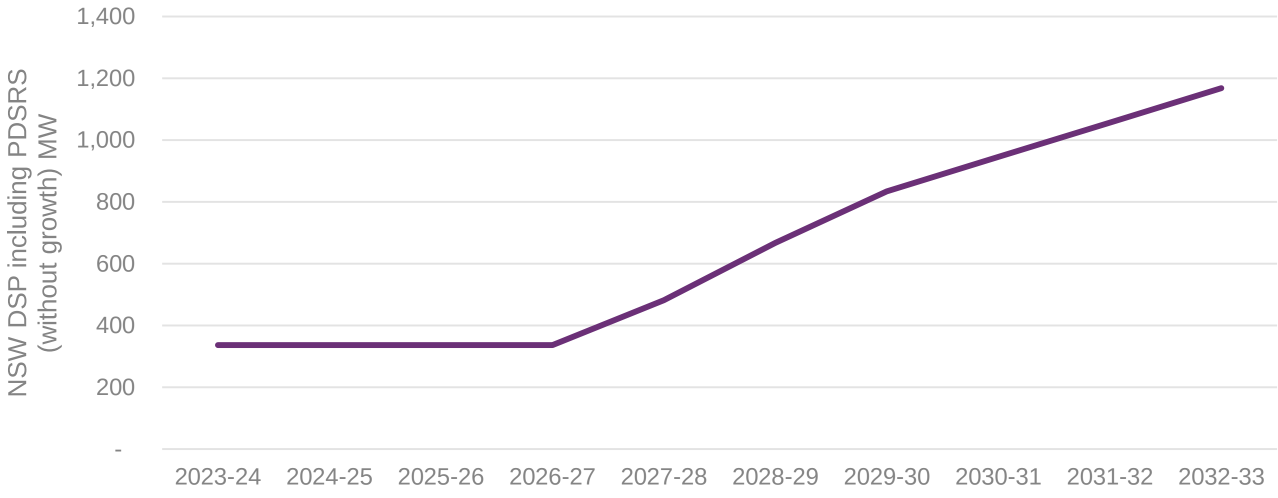
2.2.8 Demand response and demand side participation

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 2023 ESOO. The amount of DSP assumed includes only existing and committed DSP projects, consistent with the 2023 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, shown in Figure 8. The scheme will, in its current design, only provide additional DSP during summer.

The values are shown without the assumption of DSP growth beyond what the PDRS is expected to deliver, which is included in other scenarios in this assessment.

Figure 8 DSP applied in forecasts for the summer period in New South Wales, considering PDRS targets, 2023-24 to 2032-33 (MW)



2.2.9 Generator auxiliary load

Generator auxiliaries, which are used in the calculation of the EST, were updated to reflect the adjusted generator availability. The generator auxiliary load forecast for all years was calculated by multiplying auxiliary rates published in the 2023 IASR workbook[24] by the firm available capacity for each generator, then summing them.

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 7 for each financial year. The two largest generating units in New South Wales in 2023-24 are 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, with 675 MW summer peak rating) becomes the second largest unit.

Table 7 Assumed reserve margin (MW, summer peak capacity)

	Unit 1	Unit 2	Reserve
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
2032-33	MP1	MP2	1,380

[24] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

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.

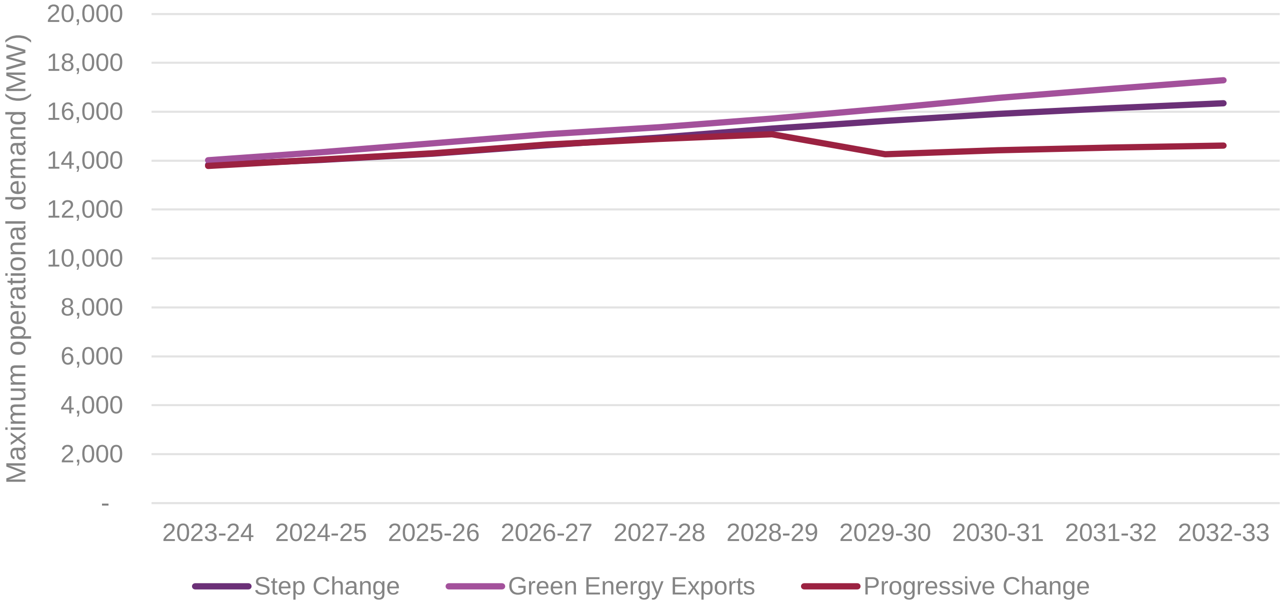
As such, AEMO has assessed the EST against each scenario and relevant sensitivity used in the 2023 ESOO, as applicable to New South Wales.

Three demand scenarios were considered in the 2023 ESOO, as summarised in Table 8 below. Figure 9 shows the 2023 ESOO's 10-year maximum demand forecast for New South Wales for all three scenarios.

Table 8 Description of scenarios for the EST assessment

Scenario	Description
***Step Change* (ESOO Central scenario)**	Achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in CER, including electrification of the transportation sector.
Green Energy Exports	Reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation
Progressive Change	Meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.

Figure 9 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 included in the 2023 ESOO. These have been assessed under the demand forecasts associated with the Central scenario:

- *CER orchestration and DSP growth* – this sensitivity includes growth in CER orchestration and DSP. In previous assessments growth was assumed in the Central scenario, but this assumption is now a sensitivity due to revised assumptions in the 2023 ESOO.
- *Actionable transmission projects* – this sensitivity includes generation and storage that is existing, committed, or committed*, and transmission that is anticipated or actionable in the 2023 ISP. This sensitivity also includes anticipated generation projects and CER orchestration and DSP growth.
- *Federal and state schemes* – this sensitivity includes numerous federal, state and territory government schemes and programs that have been implemented to further incentivise or directly fund additional generation and storage developments in the NEM. This sensitivity also includes anticipated generation projects and CER orchestration and DSP growth.
- *Schemes without CER orchestration* – this sensitivity is the same as the *Federal and state schemes* sensitivity but does not include CER orchestration and DSP growth.
- *Delay Eraring retirement* – this sensitivity applies a two-year delay to the closure of the two largest units of Eraring Power Station, such that they now close after 2026-27. All other assumptions are as per the Central scenario.
- *2022 methodology* – this sensitivity removes some of the changed assumptions made from the 2022 ESOO to the 2023 ESOO. Delays to commissioning dates are not applied and growth in CER orchestration (virtual power plant (VPP) and vehicle-to-grid (V2G)) is applied.
- *Infrastructure tender 2 and 3* - In addition to the above sensitivities, the EST has also been assessed under an additional sensitivity considering the impact of the Firming Tender (Tender 2) and Generation and Long-Duration Storage Infrastructure (Tender 3) that aims to increase available capacity in New South Wales. The tenders have been conducted by AEMO Services, acting as the NSW Consumer Trustee. This sensitivity also considers the development of projects classified by AEMO as ‘anticipated’. All other inputs and assumptions align with the EST Central scenario.

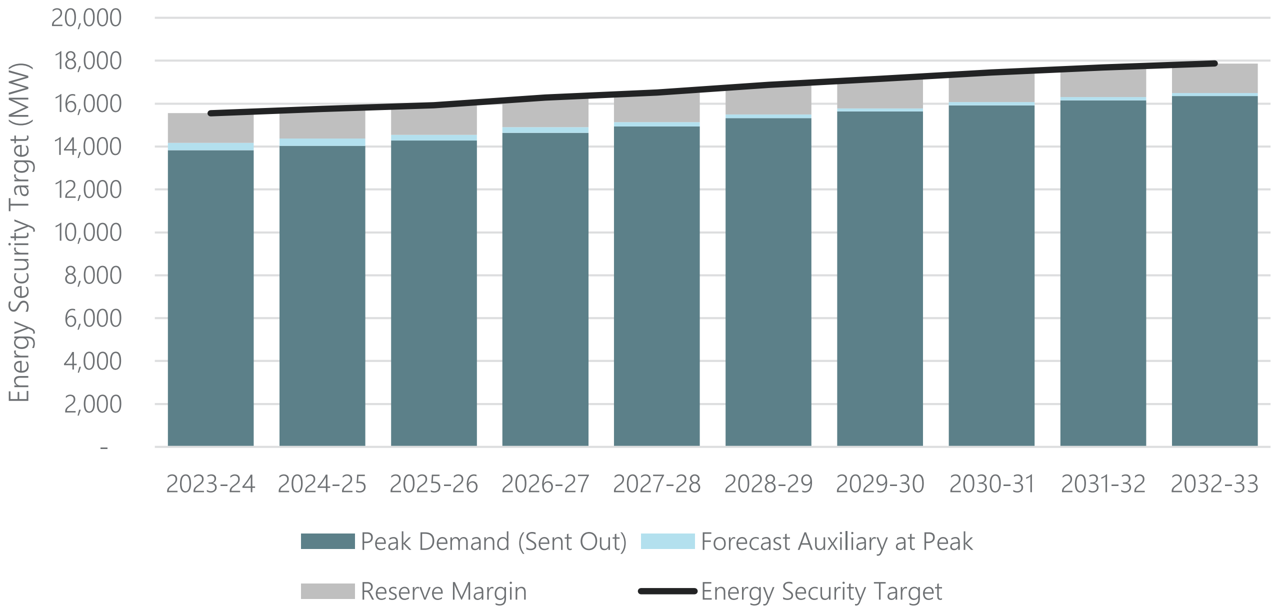
4 EST assessment

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 assumed to reduce from 1,385 MW to 1,380 MW over the horizon, as shown in Table 7 and outlined in Section 2.3. Collectively these components sum to the EST, as shown in Figure 10.

Figure 10 Central scenario forecast, EST components



Expected changes to supply in New South Wales, considering committed, committed* and those developments with LTES Agreements, are:

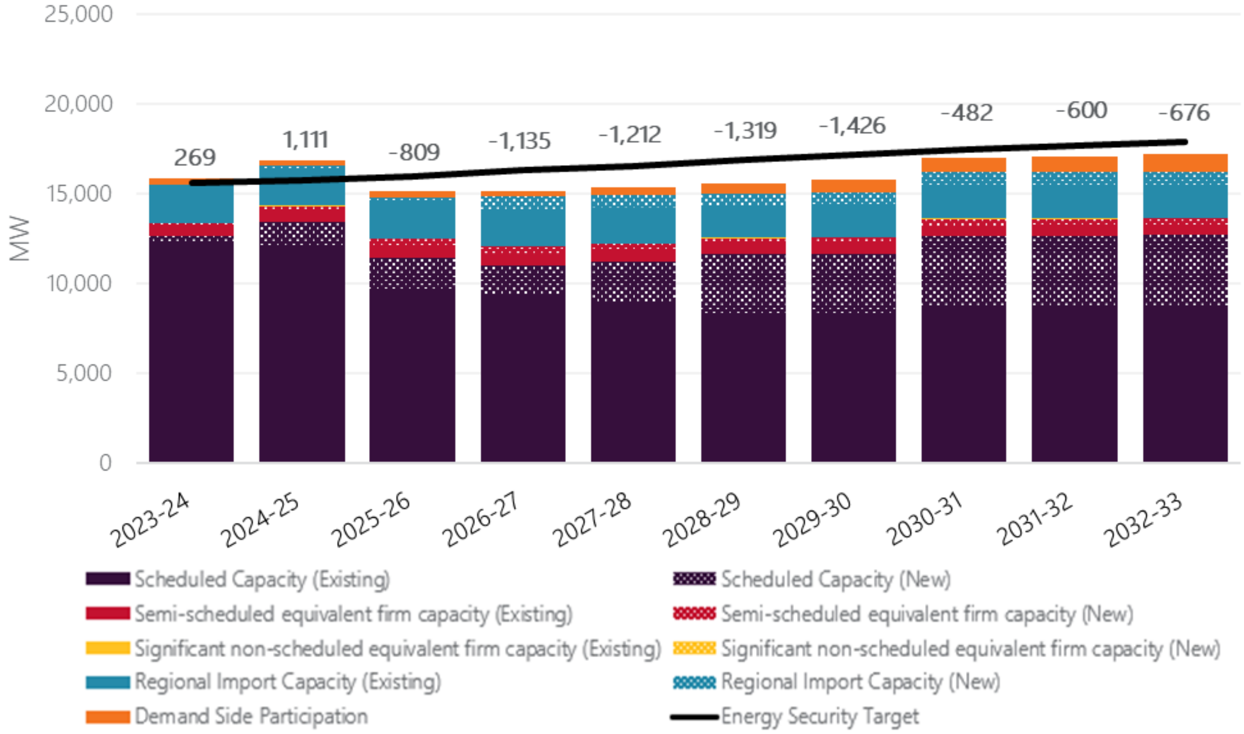
- Between summer 2022-23 and 2023-24, about 650 MW of additional variable renewable energy (VRE) generation is expected to become operational, with a total of 2,941 MW of additional VRE generation online by 2032-33.
- Between summer 2022-23 and 2023-24, about 395 MW of additional storage is expected to become operational, with a total of 3,715 MW of additional storage online by 2032-33.
- 978 MW of additional gas-fired capacity is built with operation commencing in the summer of 2024-25. This includes the Kurri Kurri and Tallawarra B power stations.
- The Waratah Super Battery is included and is assumed to operate partly as transmission support for the NSW SIPS from 2025-26 to 2029-30 and then operate as a commercial battery.

- Facilities supported by the New South Wales Government under LTES Agreements are included, including Stubbo Solar Farm, Coppabella Wind Farm, New England Solar Farm and Limondale BESS.
- Energy Australia's 318 MW gas generator Tallawarra B is considered operational from 2024-25.
- The 2,880 MW Eraring Power Station is scheduled to retire in August 2025.

The capability of the transmission system is also expected to improve with the Hunter Transmission Project from 2027-28, declared as a Priority Transmission Infrastructure Project.

Figure 11 shows the projected assessment of the EST for this Central scenario considering the changes to existing and committed supply. A breach is forecast in 2025-26 following the exit of Eraring Power Station, and in each of the remaining years of the horizon.

Figure 11 Central scenario, assessment of the EST with existing and committed supply



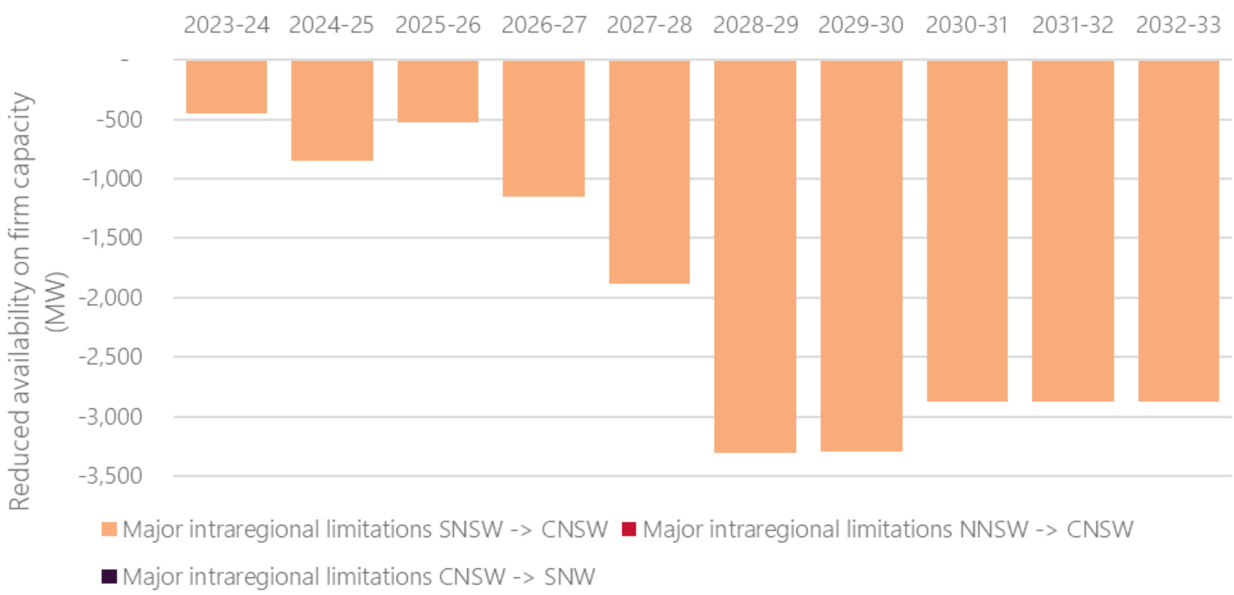
Key considerations in, and observations from, the assessment are:

- Existing firm capacity is forecast to be sufficient to meet the EST at the start of the horizon.
- Additional semi-scheduled and scheduled generation capacity is expected to become available primarily in the SNSW sub-region, including the Snowy 2.0 project (2,200 MW).
- Committed interconnector import capacity is expected to become available over the horizon from Project EnergyConnect (150 MW from 2024-25 and 800 MW 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 12, are expected to constrain this proposed capacity from being fully available to consumers in the CNSW and SNW sub-regions during peak demand periods.

- A target breach is forecast in 2025-26 onwards, when Eraring Power Station in the SNW sub-region retires. At this point, firm capacity from outside this sub-region would be called upon 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 to 2032-33 when considering only those projects that are committed, committed* or have an LTES Agreement, additional generation and transmission projects are anticipated or are deemed actionable in the 2022 ISP[25], and if these are delivered to schedule and capacity then the breaches are not forecast (see the sensitivity assessments in Section 4.2).
- 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 interconnector capacity, only if supported with appropriate intra-regional transmission investments.

Figure 12 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 12 Central scenario, estimated impact of transmission limits on firm capacity



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

Changes from October 2022 ESTM

The 2023 ESTM Report has been updated with the latest assumptions from the 2023 ESOO and the most recent ISP Methodology and IASR. These changes have resulted in higher breaches between 2025-26 and 2029-30 including additional breaches in 2027-28 and 2028-29.

The material drivers affecting changes in the 2023 ESTM assessment are outlined below:

- Increases in maximum demand due to higher underlying demand from business mass market loads.
- No orchestrated CER growth included, that is, not existing capacity or identified as committed developments.
- Lower DSP projected, mainly in the middle years of forecast.
- Changes to generator new entrants, retirements and capacities, including the announced delay to the retirement of Vales Point, increased capacity of Snowy 2.0 once connected, and additional projects compared to the previous ESTM assessment as outlined in AEMO's July 2023 Generator Information publication.
- Changes to interconnector limits.
- Sub-regional interconnector limits based on the single largest unit rather than the two largest units being unavailable (while retaining the regional requirement based on the largest two units being unavailable)

Consideration of energy limits and limited duration energy storage

In the 2022 ESTM Report, AEMO identified that EST surpluses are highly dependent on simplified factors that may not adequately align with the actual risks to consumers that are represented in a more comprehensive reliability assessment such as the ESOO. AEMO recommended that further investigation of these factors be considered in future EST assessments, particularly 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 peak demand and supply scarcity.

In this 2023 ESTM Report, in consultation with the Department, AEMO has maintained the methodology deployed in the 2022 ESTM Report. However, as identified in the 2023 ESOO, AEMO considers that the capacity contribution that shallow duration batteries may provide to customer reliability is significantly less than other storage types with deep energy storages, or other firm capacity technologies. For the 2023 ESOO, following consultation with stakeholders, AEMO derated the energy stored in shallow duration energy storages to account for the probable effect of imperfect foresight in the operation of the National Electricity Market, as forecasting models over-optimise stored energy given the perfect foresight of the models.

For the EST calculation, no consideration has been given to the duration of stored energy that may be available at times of peak demand for New South Wales consumers, and AEMO therefore considers that this methodology will tend to over-estimate EST surpluses, particularly as shallow duration storages (such as 1-4 hour batteries, and relatively shallow CER devices) provide an increasing amount of firm capacity in the EST assessment.

AEMO recommends that the methodology for the 2024 ESTM Report consider alternative methodologies to better capture the risks that may develop with greater reliance on energy-limited firm capacity.

Consideration of interconnector utilisation

Analysis demonstrates that inter-regional transfer capacity tends to be constrained at times of peak demand due to coincident high demand in neighbouring regions. AEMO considers that the EST assessment should account for the likelihood that inter-regional capacity may not be available at times of peak demand by appropriately derating their available capacity, particularly when the neighbouring region has forecast reliability risks above the relevant reliability standard in the most recent ESOO.

Consideration of Anticipated generation projects

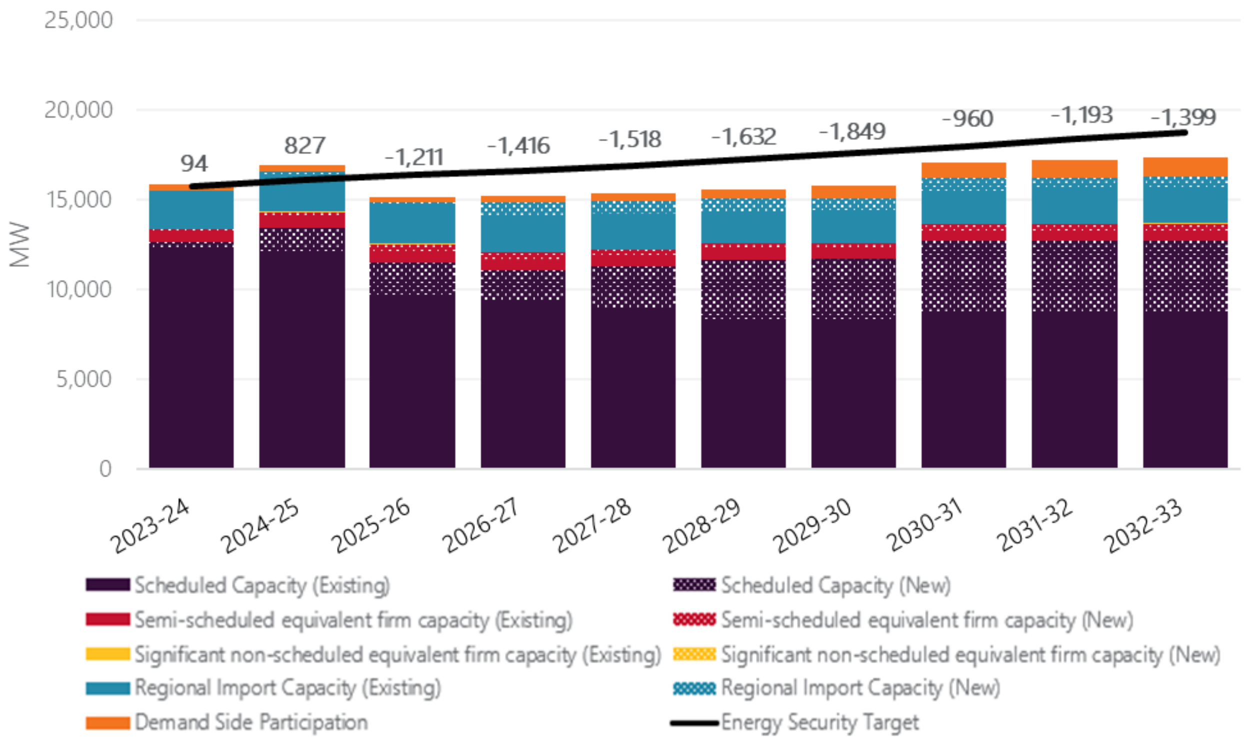
AEMO has also begun including Anticipated generation projects in the ESOO's reliability forecast, following consultation with stakeholders. AEMO considers that projects designated as Anticipated are likely to progress to final commissioning and while these projects are yet to demonstrate full commitment, AEMO consider it is appropriate to include these projects in the EST assessment. AEMO recommends considering a methodology refinement to include Anticipated projects for the 2024 ESTM Report.

4.2 Alternative scenarios and sensitivities

4.2.1 Green Energy Exports

The *Green Energy Exports* scenario explored a higher demand future relative to the Central Scenario, with stronger population and economic growth, and stronger electrification (including of transport). The assessment under this scenario is shown in Figure 13. This assessment has a breach of the EST in all years apart from 2023-24 and 2024-25.

Figure 13 *Green Energy Exports* scenario, assessment of the EST

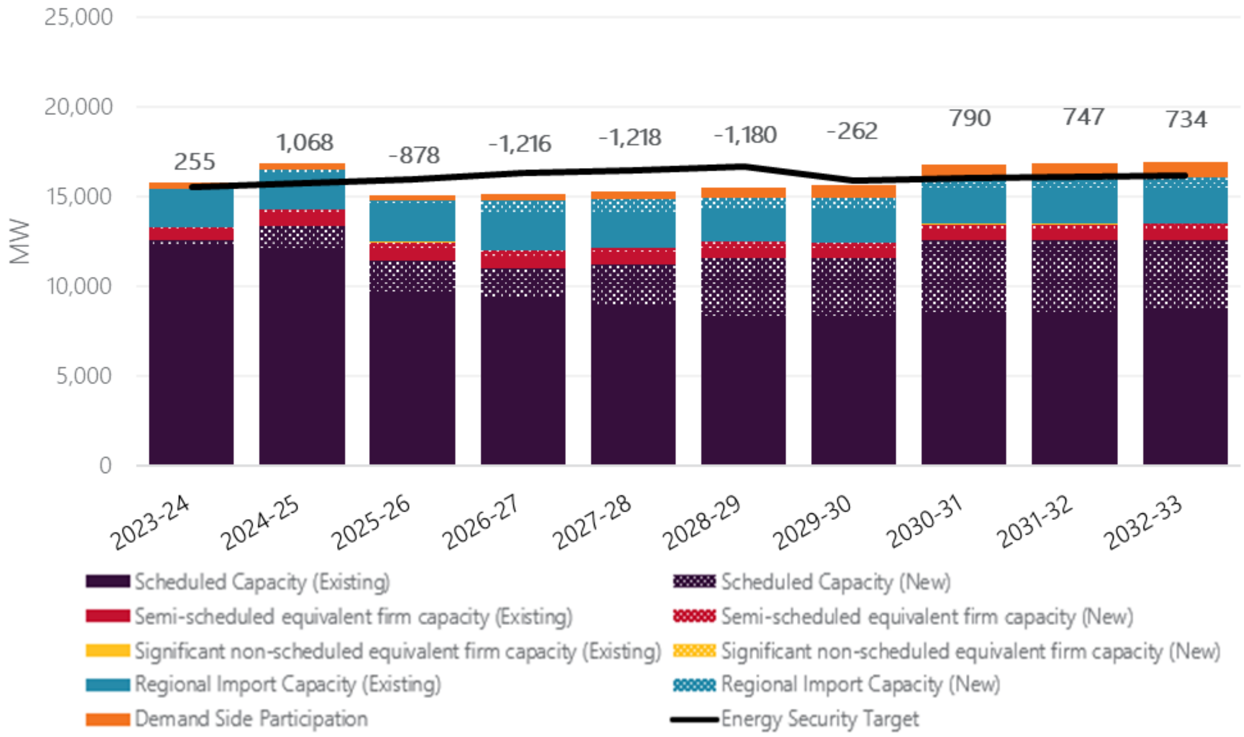


4.2.2 Progressive Change

The EST assessment for the *Progressive Change* scenario is shown in Figure 14. The *Progressive Change* scenario varies from the Central scenario (*Step Change*) mainly due to differences in demand arising from lower growth in population and economic activity later in the horizon, as well as assumed closures of some large industrial loads. It also has a slower uptake of EVs. This scenario has breaches from 2025-26 until 2029-30, with a surplus from 2030-31 onwards.

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 2025-26 and 2026-27 indicates an increased need for additional firm capacity in this scenario if CER uptake is slower than forecast in the Central scenario.

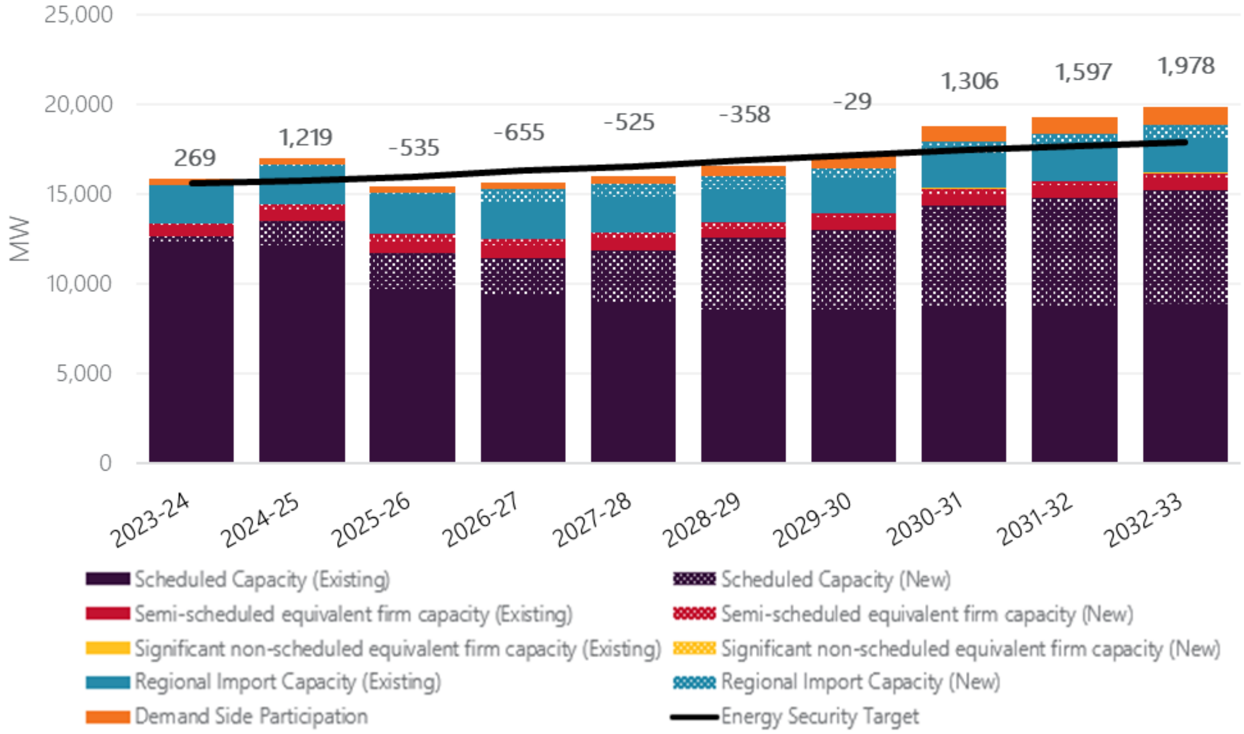
Figure 14 *Progressive Change* scenario, assessment of the EST



4.2.3 *CER orchestration and DSP growth* (sensitivity on the Central scenario)

The EST assessment under the *CER orchestration and DSP growth* sensitivity is shown in Figure 15. Under this sensitivity the EST is breached from 2025-26 until 2029-30.

Figure 15 *CER orchestration and DSP growth*, **assessment of the EST**



4.2.4 *Actionable transmission projects* (sensitivity on the Central scenario)

This sensitivity included transmission projects that were anticipated or deemed actionable in the 2022 ISP, as well as generation projects that are committed, committed* or have an LTES agreement. This sensitivity also included anticipated generation projects and CER orchestration and DSP growth. Anticipated generation projects were not included.

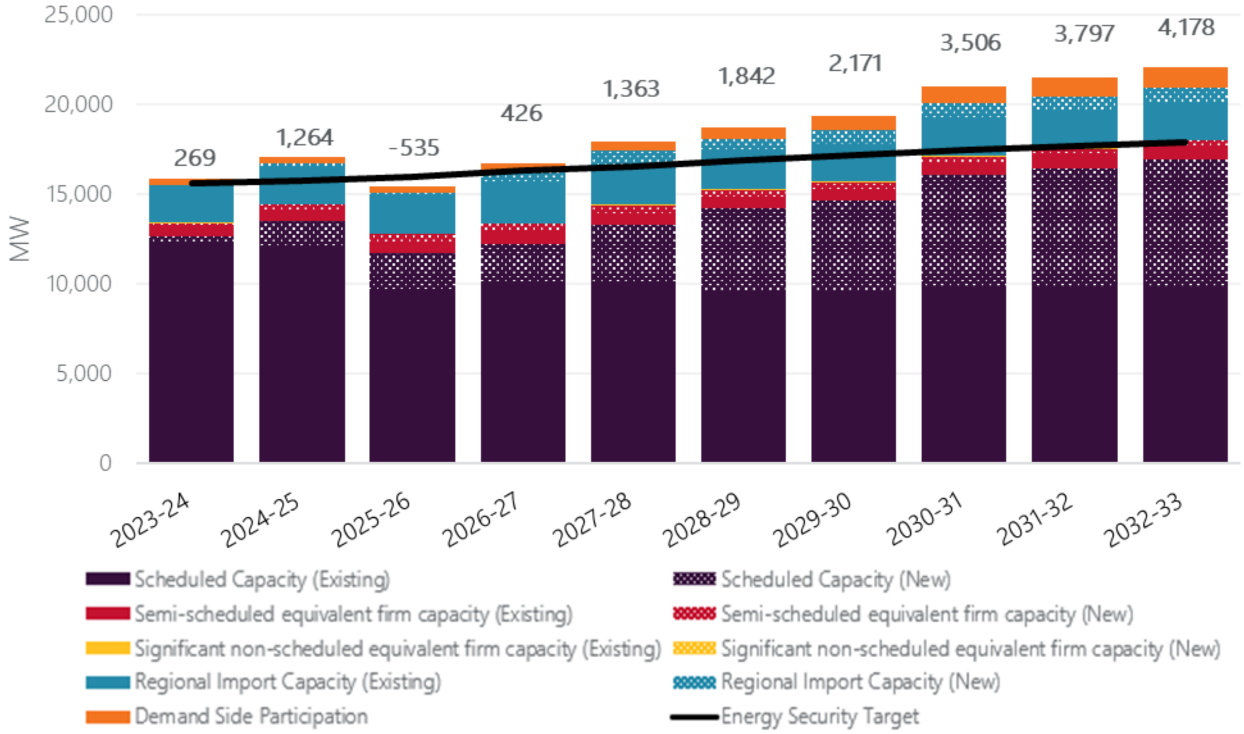
The EST assessment under the *Actionable transmission* sensitivity is shown in Figure 16. Under this sensitivity, there is a breach of the EST in 2025-26 prior to new transmission being commissioned, and there is a large EST surplus in later years.

Additional transmission projects that were included as anticipated or actionable but not committed include the HumeLink (from 2026-27) and New England Expansion (from 2028-29) transmission projects[26].

These projects are forecast to significantly increase intra-regional transfer limits into the Sydney-Newcastle-Wollongong sub-region, thereby allowing already committed firm capacity to be more available to New South Wales electricity customers during peak demand periods.

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

Figure 16 ***Actionable transmission projects*, assessment of the EST**



4.2.5 *Federal and state schemes* (sensitivity on the Central scenario)

The *Federal and state schemes* sensitivity included additional projects that have been announced by the Federal Government or New South Wales Government but have not yet been sufficiently progressed to be included in the Central sensitivity. This included:

- Additional projects under the New South Wales Government's firming infrastructure tender, which was assumed to be 930 MW from 2025-26. AEMO notes that this tender has not been finalised, and has assumed that this additional 930 MW is located in the SNW region.
- Additional projects under the New South Wales Government's Infrastructure Investment Objectives (IIO) tender, which was assumed to be 350 MW from 2028-29 and 1,950 MW from 2030-31.

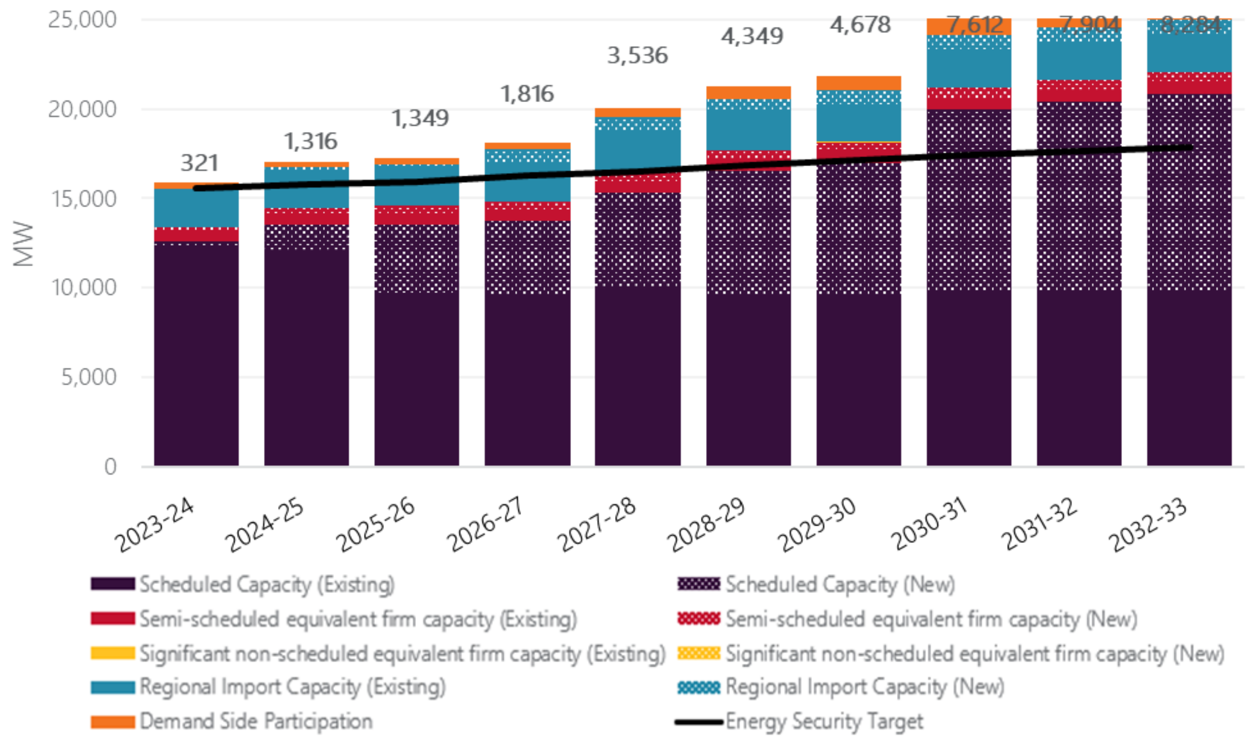
The following were also included:

- The anticipated and actionable transmission developments described in the previous section.
- Projects designated as 'Anticipated' in the September Generation Information publication[27] ; this included 838 MW of VRE generation and 1,118 MW of storage.

The EST assessment under this sensitivity is shown in Figure 17. Under this sensitivity there is no breach of the EST, with sufficient near-term developments to avoid the observed breaches in the Central scenario, and a large surplus projected by the end of the horizon.

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

Figure 17 ***Federal and state schemes*****, assessment of the EST**

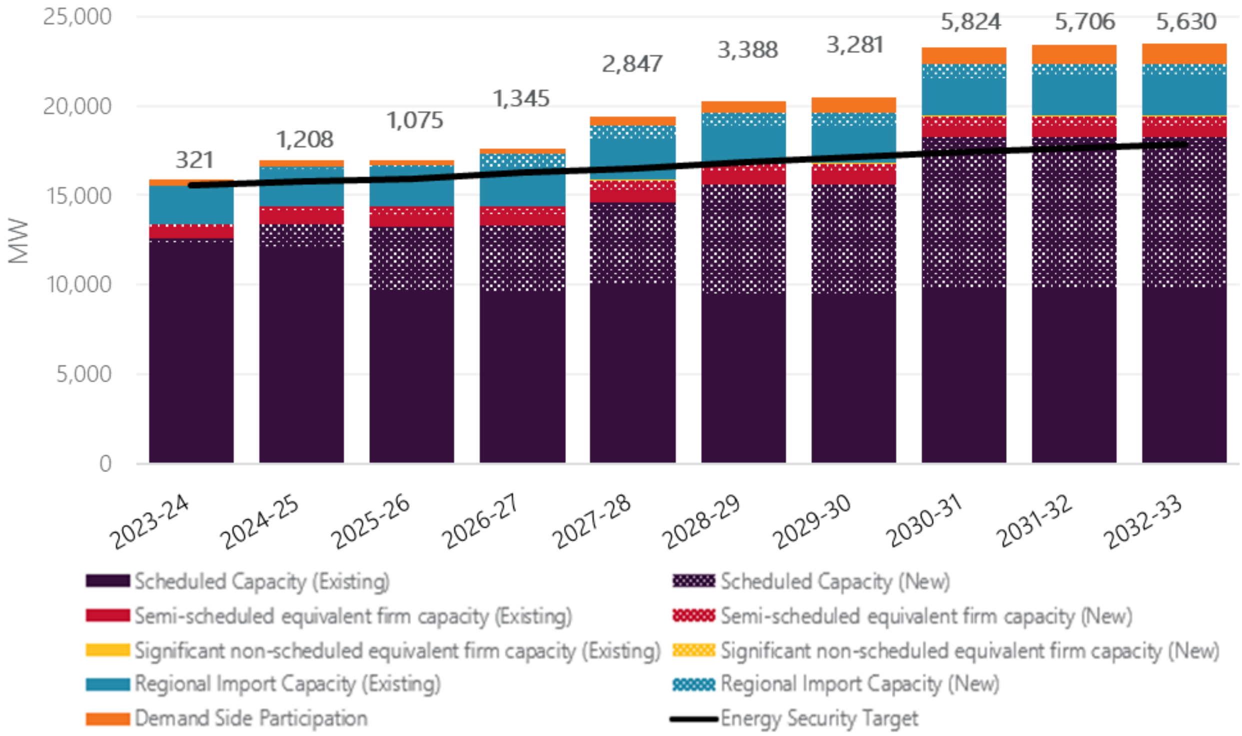


4.2.6 *Schemes without CER orchestration* (sensitivity of the Central scenario)

This sensitivity is the same as the *Federal and state schemes* sensitivity but removed growth in CER orchestration.

The assessment under this sensitivity is shown in Figure 18. It is similar to the results from the *Federal and state schemes sensitivity* but is lower due to the absence of the CER orchestration assumption.

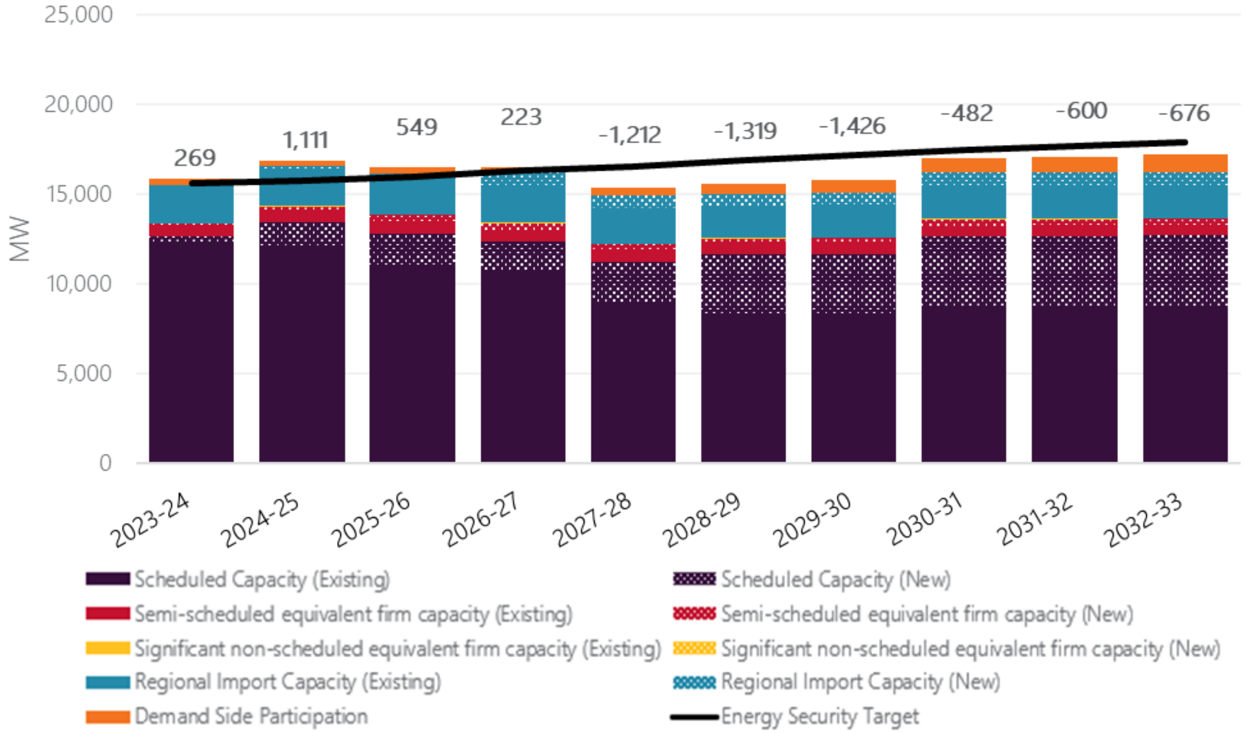
Figure 18 ***Schemes without CER orchestration*** **sensitivity, assessment of the EST**



4.2.7 *Delay Eraring retirement* (sensitivity of the Central scenario)

This sensitivity applied a two-year delay to the retirement of the two largest units of Eraring Power Station, leading to their retirement after 2026-27. This led to an improved EST during the additional two years the units operate, in 2025-26 and 2026-27, and addresses the EST breaches in these two years. Other years remain the same as the Central scenario. The EST assessment for this sensitivity is shown in Figure 19.

Figure 19 Delay Eraring retirement, assessment of the EST



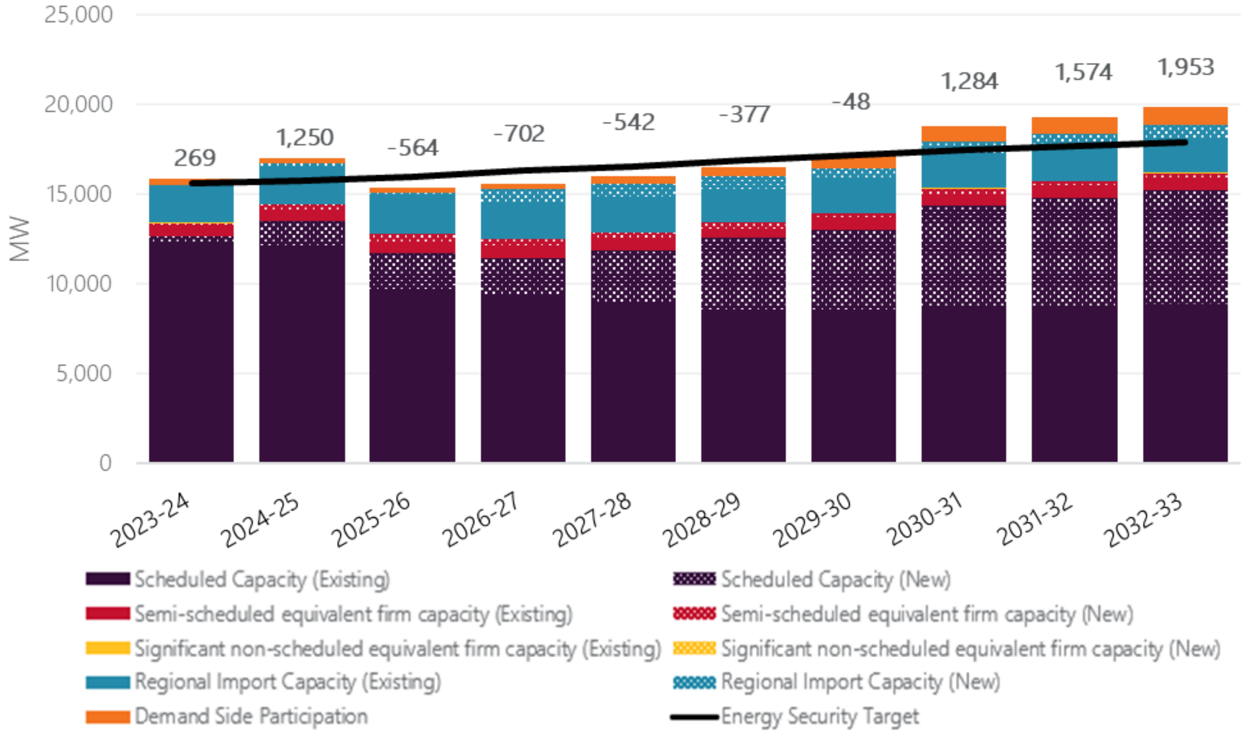
4.2.8 *2022 methodology* (sensitivity of the Central scenario)

The *2022 methodology* sensitivity was based on a sensitivity included in the 2023 ESOO, which removed the impact of changed assumptions since the 2022 ESOO. For this sensitivity:

- Delays from the advised Full Commercial Use Date of generation projects that are Committed or Committed* were not applied.
- Growth in VPP and V2G was included.

Both of these factors have the effect of adding additional capacity to meet the EST. The EST assessment under this sensitivity is shown in Figure 20. Under these conditions there are smaller breaches of the EST from 2025-26 until 2029-30, and a surplus from 2030-31 onwards.

Figure 20 ***2022 methodology*, assessment of the EST**



4.2.9 *Infrastructure tenders 2 and 3* (sensitivity of the Central scenario)

Since publishing the 2023 ESOO in August 2023, AEMO Services has announced the outcomes of their second tender for firming infrastructure, and of their third tender for generation and long-duration storage infrastructure[28].

While the impact of these tenders was assessed in the *Federal and State Scheme sensitivity*, this assumed target quantities or generation and storage at default locations consistent with assumptions applied to the equivalent sensitivity in the 2023 ESOO. Since the specific project details are now known, these specifications are applied to this *Infrastructure tenders 2 and 3 sensitivity*.

The *Infrastructure tenders 2 and 3 sensitivity* is included in this EST Monitor report at the request of the New South Wales government Office of Energy and Climate Change. The sensitivity is applied once with assumed development delays applied consistently with the ESOO methodology, and again without development delays.

For this sensitivity, all assumptions align with the Central scenario except:

- Projects classified by AEMO as 'anticipated' are included, subject to default development delays in the first EST analysis.
- Tender 2 and Tender 3 recipient projects are included, where development delays are applied in the first EST analysis at the earliest of either a 1 year delay to the advised commissioning target date, or the relevant LTESA sunset date.

The anticipated projects and tender recipients add additional capacity to meet the EST relative to the Central scenario. The EST assessment under this sensitivity is shown in Figure 21 and Figure 22.

[28] See https://aemoservices.com.au/tenders

Consistent with the Central scenario, an EST breach is identified in 2025-26 when development delays are applied, following the retirement of Eraring Power Station. While numerous anticipated projects and Tender 2 recipient projects are targeting completion in advance of Summer 2025-26, default delays apply this capacity in the 2026-27 year. When these projects are assumed to commission at the commissioning target dates advised, the EST breach is no longer forecast to occur. From 2026-27, an EST surplus is projected, which grows over the remainder of the horizon as further developments as part of Tender 3 are considered.

Figure 21 ***Infrastructure tenders 2 and 3 sensitivity with development delays, assessment of the EST***

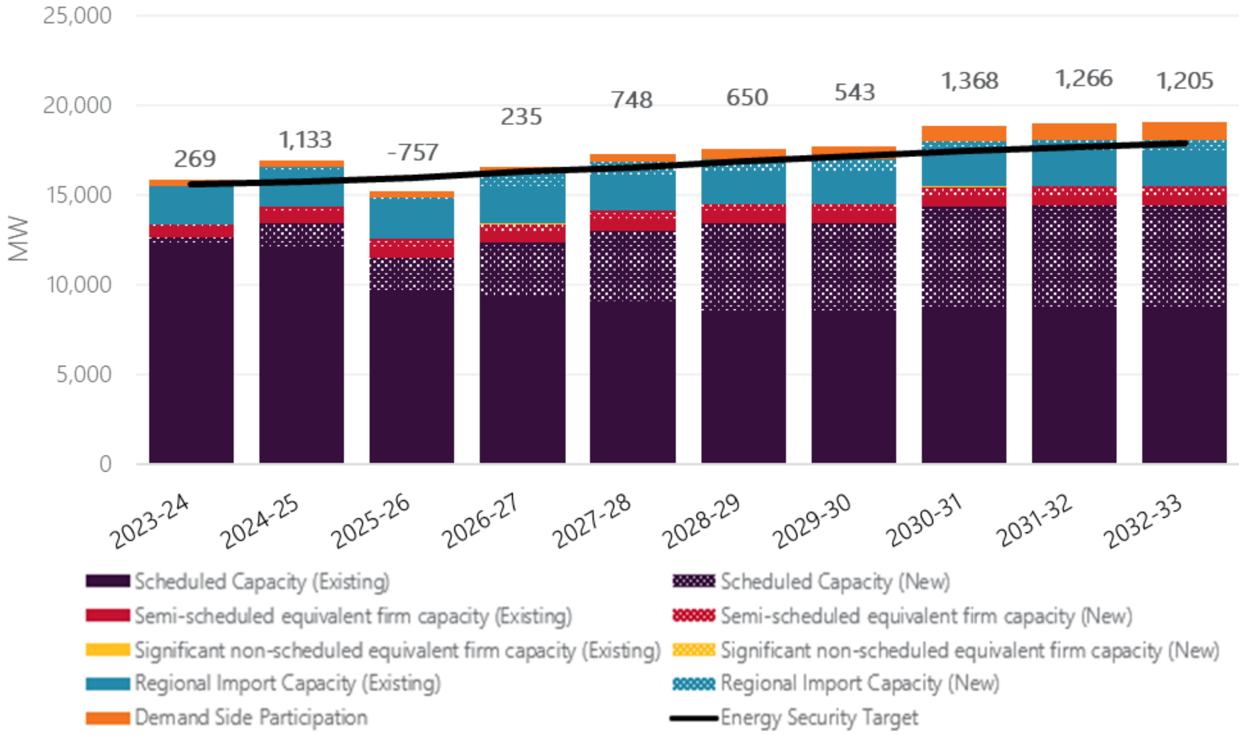
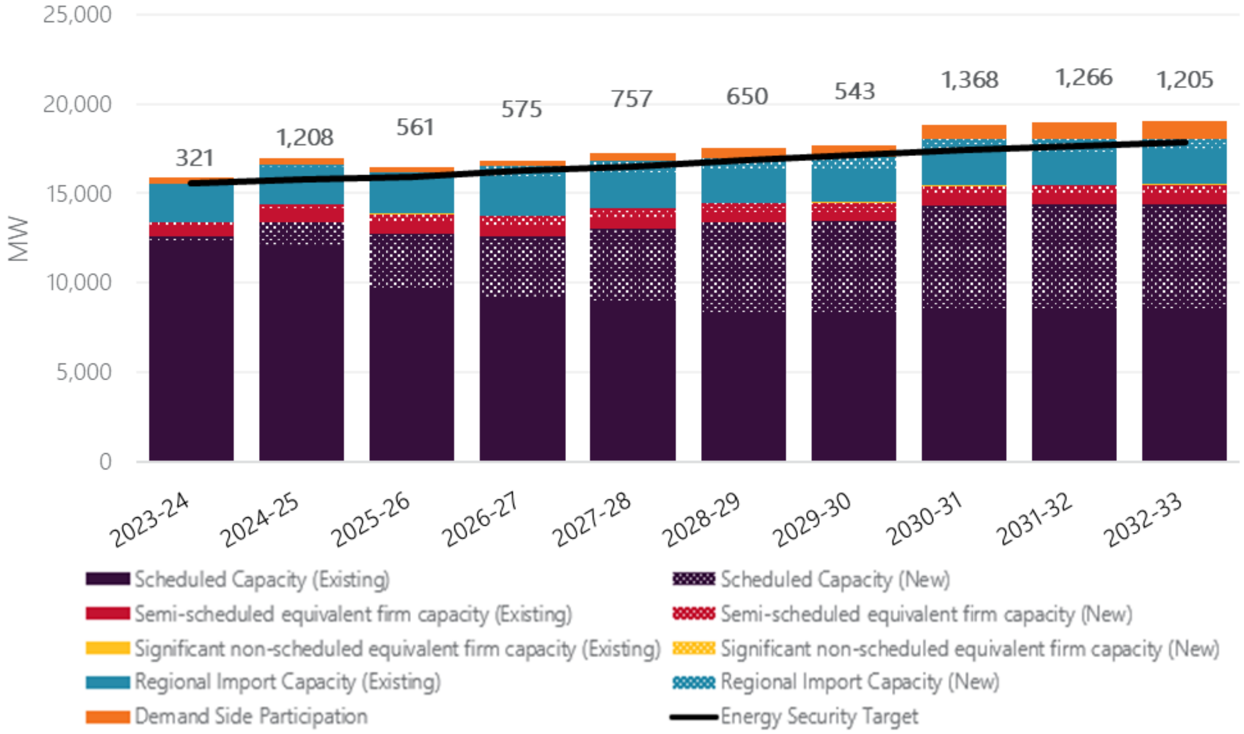


Figure 22 ***Infrastructure tenders 2 and 3 sensitivity at target commissioning dates*, assessment of the EST**



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 in the Central scenario against AEMO's 10% POE demand trace[29], and counted how many times operational sent out demand for a thirty-minute interval 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 are incidents forecast in 2025-26 onwards. For each of these years, the size of the EST breach and threshold are shown in Table 9.

Table 9 Size of EST breach and threshold (MW), Central scenario

Year	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
EST surplus/ breach	269	1,111	-809	-1,135	-1,212	-1,319	-1,426	-482	-600	-676
Threshold	No breach	No breach	13,475	13,502	13,727	13,999	14,205	15,427	15,547	15,668

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

- Figure 23 the monthly distribution of the periods that exceed the demand threshold as a percent of all periods that exceed the demand threshold, highlighting that reserve is expected to fall below the required margin primarily during summer but there are winter breaches in 2025-26 to 2029-30.
- Figure 24 shows the projected frequency of incidents between summer and winter per year, showing similar results to the seasonal results in the monthly analysis shown in Figure 23.
- Figure 25 shows the projected incident duration. There is a wide distribution of incident durations, with incidents of up to 5.5 hours in length.

[29] 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 23 Projected monthly distribution of incidents by forecast month and financial year, Central scenario, 2023-24 to 2032-33

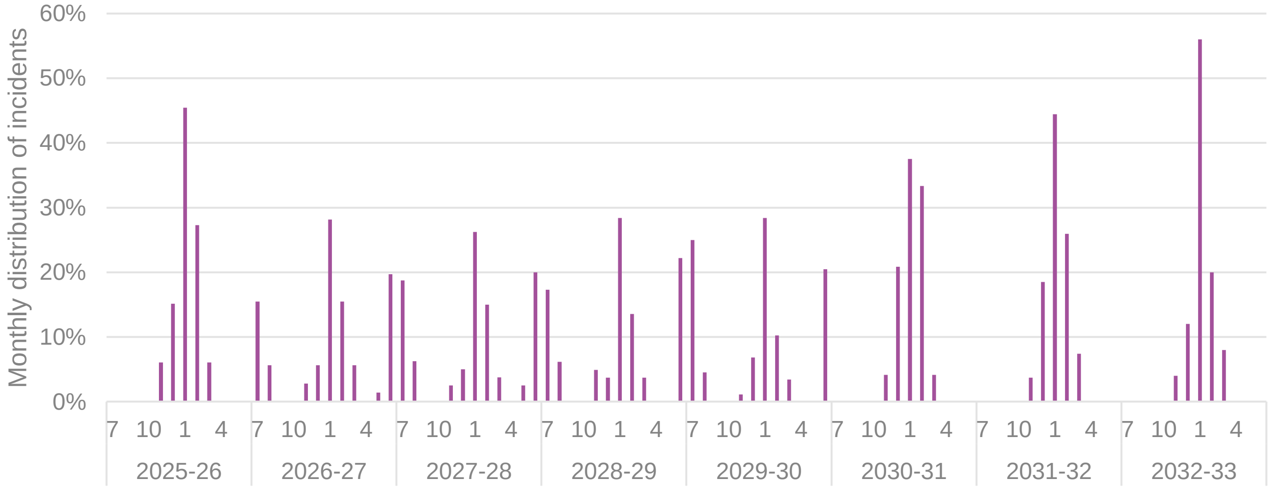


Figure 24 Projected seasonal distribution of incidents, Central scenario, 2023-24 to 2032-33

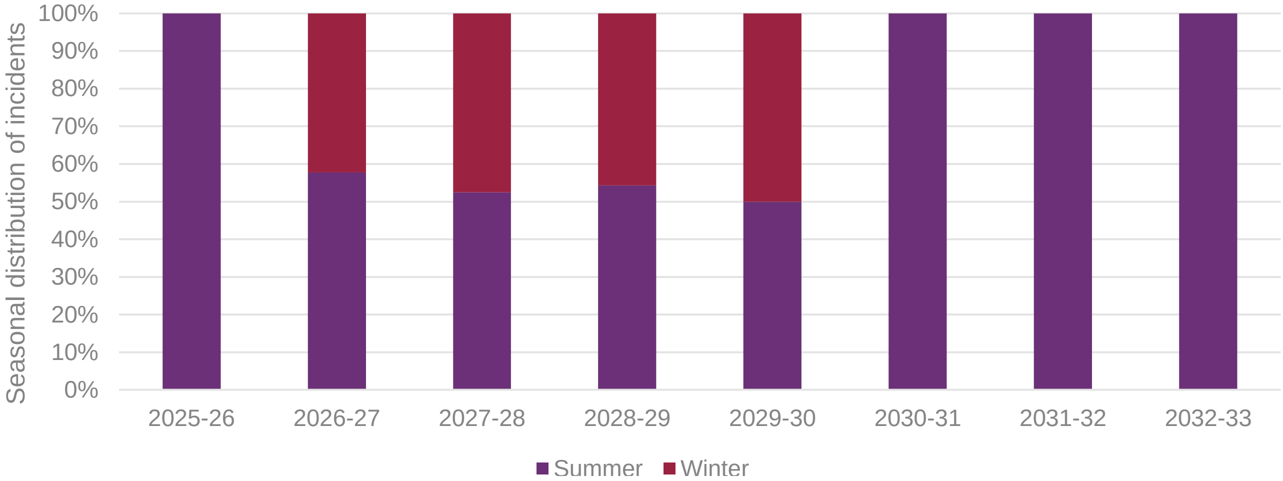
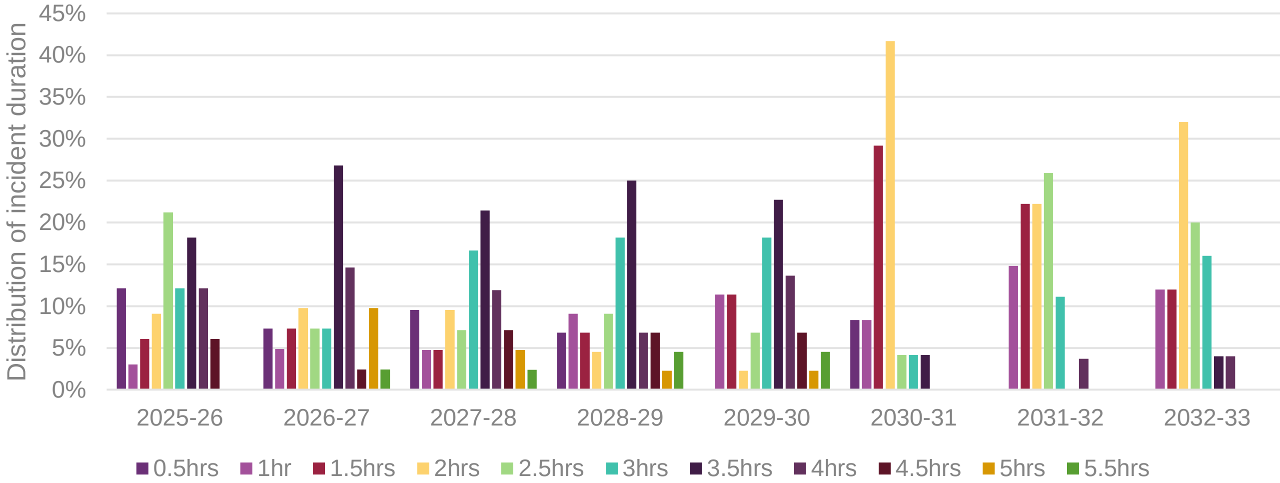


Figure 25 Projected incident duration (Summer), Central scenario, 2023-24 to 2032-33



6 EST assessment outcomes – tables

The EST assessment outcomes are shown in the following tables.

Table 10 Central scenario, EST assessment (MW)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,344	12,115	9,702	9,340	8,961	8,316	8,338	8,624	8,634	8,643
Scheduled capacity (new)	248	1,279	1,733	1,666	2,249	3,294	3,301	4,013	4,017	4,021
Semi-scheduled equivalent firm capacity (existing)	654	640	650	625	599	555	556	575	576	576
Semi-scheduled equivalent firm capacity (new)	76	240	396	380	365	338	339	350	350	351
Significant non-scheduled equivalent firm capacity (existing)	26	25	25	24	23	22	22	23	23	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	328	321	326	313	429	551	689	808	905	1,001
Interconnector import capacity (existing)	2,144	2,100	2,132	2,049	1,963	1,819	1,823	1,885	1,887	1,890
Interconnector import capacity (new)	-	143	145	743	712	660	661	684	685	686
Firm (or equivalent) capacity	15,819	16,863	15,109	15,141	15,301	15,553	15,729	16,963	17,076	17,190
EST surplus / deficit	**269**	**1,111**	**-809**	**-1,135**	**-1,212**	**-1,319**	**-1,426**	**-482**	**-600**	**-676**

Table 11 Green Energy Exports scenario, EST assessment (MW)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	14,019	14,351	14,708	15,080	15,364	15,726	16,132	16,562	16,942	17,292
Forecast auxiliary at peak	329	316	254	116	94	97	94	33	30	32
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,733	16,052	16,342	16,576	16,838	17,203	17,606	17,975	18,352	18,704
Scheduled capacity (existing)	12,354	12,130	9,719	9,354	8,975	8,328	8,355	8,643	8,658	8,673
Scheduled capacity (new)	243	1,276	1,732	1,664	2,248	3,294	3,303	4,017	4,024	4,031
Semi-scheduled equivalent firm capacity (existing)	655	641	651	626	600	556	557	576	577	578
Semi-scheduled equivalent firm capacity (new)	76	240	397	381	365	338	339	351	351	352
Significant non-scheduled equivalent firm capacity (existing)	26	25	26	25	23	22	22	23	23	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	328	321	326	314	430	552	691	830	946	1,063
Interconnector import capacity (existing)	2,146	2,102	2,135	2,052	1,966	1,822	1,826	1,890	1,893	1,896
Interconnector import capacity (new)	-	143	145	744	713	661	663	686	687	688
Firm (or equivalent) capacity	15,827	16,878	15,131	15,159	15,320	15,572	15,756	17,015	17,159	17,304
EST surplus / deficit	**94**	**827**	**-1,211**	**-1,416**	**-1,518**	**-1,632**	**-1,849**	**-960**	**-1,193**	**-1,399**

Table 12 Green Energy Exports scenario, EST assessment (MW)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,788	14,042	14,306	14,661	14,888	15,078	14,267	14,420	14,531	14,611
Forecast auxiliary at peak	336	320	249	266	196	209	201	184	183	184
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,509	15,747	15,935	16,307	16,464	16,667	15,848	15,984	16,094	16,175
Scheduled capacity (existing)	12,341	12,114	9,701	9,339	8,956	8,303	8,285	8,569	8,573	8,577
Scheduled capacity (new)	197	1,233	1,682	1,617	2,201	3,246	3,237	3,942	3,944	3,946
Semi-scheduled equivalent firm capacity (existing)	654	640	650	625	598	554	553	571	572	572
Semi-scheduled equivalent firm capacity (new)	76	240	396	380	364	337	336	348	348	348
Significant non-scheduled equivalent firm capacity (existing)	26	25	25	24	23	22	22	22	22	22
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	328	321	326	313	429	550	685	768	828	888
Interconnector import capacity (existing)	2,144	2,099	2,131	2,049	1,962	1,816	1,811	1,873	1,874	1,875
Interconnector import capacity (new)	-	143	145	743	712	659	657	680	680	680
Firm (or equivalent) capacity	15,764	16,815	15,058	15,091	15,246	15,487	15,586	16,774	16,841	16,909
EST surplus / deficit	255	1,068	-878	-1,216	-1,218	-1,180	-262	790	747	734

Table 13 ***CER orchestration and DSP growth* scenario, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,344	12,118	9,706	9,358	9,003	8,401	8,457	8,745	8,777	8,811
Scheduled capacity (new)	248	1,369	1,971	2,073	2,858	4,112	4,503	5,600	5,976	6,396
Semi-scheduled equivalent firm capacity (existing)	654	641	651	626	602	561	564	583	585	588
Semi-scheduled equivalent firm capacity (new)	76	240	396	381	366	341	343	355	356	358
Significant non-scheduled equivalent firm capacity (existing)	26	25	25	25	24	22	22	23	23	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	327	335	356	361	448	573	717	839	941	1,044
Interconnector import capacity (existing)	2,144	2,100	2,133	2,053	1,972	1,837	1,849	1,912	1,919	1,926
Interconnector import capacity (new)	-	143	145	745	716	667	671	694	696	699
Firm (or equivalent) capacity	15,819	16,971	15,383	15,622	15,989	16,514	17,127	18,751	19,274	19,844
EST surplus / deficit	269	1,219	-535	-655	-525	-358	-29	1,306	1,597	1,978

Table 14 *Actionable transmission* scenario, EST assessment (MW)

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,249	12,120	9,706	10,006	10,066	9,520	9,544	9,771	9,779	9,788
Scheduled capacity (new)	352	1,369	1,971	2,216	3,196	4,660	5,082	6,257	6,658	7,105
Semi-scheduled equivalent firm capacity (existing)	649	641	651	670	673	635	636	652	652	653
Semi-scheduled equivalent firm capacity (New)	91	283	396	408	409	387	387	397	397	397
Significant non-scheduled equivalent firm capacity (existing)	25	25	25	26	26	25	25	26	26	26
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	325	335	356	386	501	650	809	938	1,048	1,159
Interconnector import capacity (existing)	2,128	2,100	2,133	2,195	2,205	2,082	2,086	2,136	2,138	2,140
Interconnector import capacity (new)	-	143	145	796	800	755	757	775	776	776
Firm (or equivalent) capacity	15,819	17,016	15,383	16,702	17,876	18,714	19,327	20,951	21,474	22,044
Est surplus / deficit	**269**	**1,264**	**-535**	**426**	**1,363**	**1,842**	**2,171**	**3,506**	**3,797**	**4,178**

Table 15 ***Federal and state schemes* scenario, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,243	12,116	9,736	9,632	10,066	9,576	9,596	9,814	9,821	9,827
Scheduled capacity (new)	381	1,397	3,770	4,096	5,244	6,966	7,391	10,176	10,580	11,030
Semi-scheduled equivalent firm capacity (existing)	649	641	653	645	673	639	640	655	655	655
Semi-scheduled equivalent firm capacity (new)	121	312	440	443	535	508	509	520	521	521
Significant non-scheduled equivalent firm capacity (existing)	25	25	26	25	26	25	25	26	26	26
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	325	335	357	371	501	654	813	942	1,053	1,164
Interconnector import capacity (existing)	2,127	2,100	2,139	2,113	2,205	2,094	2,098	2,146	2,147	2,148
Interconnector import capacity (new)	-	143	146	767	800	760	761	778	779	779
Firm (or equivalent) capacity	15,871	17,068	17,267	18,092	20,050	21,221	21,833	25,057	25,581	26,151
Est surplus / deficit	321	1,316	1,349	1,816	3,536	4,349	4,678	7,612	7,904	8,284

Table 16 ***Schemes without CER orchestration* sensitivity, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,243	12,113	9,733	9,628	10,066	9,553	9,565	9,795	9,797	9,799
Scheduled capacity (new)	381	1,307	3,531	3,680	4,574	6,057	6,061	8,440	8,442	8,444
Semi-scheduled equivalent firm capacity (existing)	649	640	652	644	673	637	638	653	653	654
Semi-scheduled equivalent firm capacity (new)	121	312	440	443	535	507	507	519	519	519
Significant non-scheduled equivalent firm capacity (existing)	25	25	26	25	26	25	25	26	26	26
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	325	321	327	323	482	633	791	918	1,027	1,135
Interconnector import capacity (existing)	2,127	2,099	2,138	2,112	2,205	2,090	2,091	2,141	2,142	2,142
Interconnector import capacity (new)	-	143	145	766	800	758	759	777	777	777
Firm (or equivalent) capacity	15,871	16,960	16,992	17,621	19,361	20,260	20,436	23,269	23,383	23,497
Est surplus / deficit	**321**	**1,208**	**1,075**	**1,345**	**2,847**	**3,388**	**3,281**	**5,824**	**5,706**	**5,630**

Table 17 ***Delay Eraring retirement*, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,923	16,281	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,344	12,115	11,049	10,668	8,961	8,316	8,338	8,624	8,634	8,643
Scheduled capacity (new)	248	1,279	1,738	1,676	2,249	3,294	3,301	4,013	4,017	4,021
Semi-scheduled equivalent firm capacity (existing)	654	640	652	629	599	555	556	575	576	576
Semi-scheduled equivalent firm capacity (new)	76	240	397	383	365	338	339	350	350	351
Significant non-scheduled equivalent firm capacity (existing)	26	25	26	25	23	22	22	23	23	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	328	321	327	315	429	551	689	808	905	1,001
Interconnector import capacity (existing)	2,144	2,100	2,138	2,061	1,963	1,819	1,823	1,885	1,887	1,890
Interconnector import capacity (new)	-	143	145	748	712	660	661	684	685	686
Firm (or equivalent) capacity	15,819	16,863	16,471	16,504	15,301	15,553	15,729	16,963	17,076	17,190
Est surplus / deficit	**269**	**1,111**	**549**	**223**	**-1,212**	**-1,319**	**-1,426**	**-482**	**-600**	**-676**

Table 18 ***2022 methodology*****, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,249	12,120	9,707	9,358	9,003	8,400	8,456	8,744	8,776	8,810
Scheduled capacity (new)	352	1,369	1,971	2,073	2,858	4,112	4,503	5,600	5,976	6,396
Semi-scheduled equivalent firm capacity (existing)	649	641	651	626	602	560	564	583	585	588
Semi-scheduled equivalent firm capacity (new)	91	283	396	381	366	341	343	355	356	358
Significant non-scheduled equivalent firm capacity (existing)	25	25	25	25	24	22	22	23	23	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	325	321	326	314	431	557	699	820	920	1,020
Interconnector import capacity (existing)	2,128	2,100	2,133	2,053	1,972	1,837	1,849	1,912	1,919	1,926
Interconnector import capacity (new)	-	143	145	745	716	667	671	694	696	699
Firm (or equivalent) capacity	15,819	17,002	15,354	15,575	15,971	16,496	17,107	18,729	19,251	19,819
Est surplus / deficit	**269**	**1,250**	**-564**	**-702**	**-542**	**-377**	**-48**	**1,284**	**1,574**	**1,953**

Table 19 ***Infrastructure tender 2 and 3 sensitivity without development delays*, EST assessment (MW)**

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,243	12,113	9,724	9,246	8,951	8,376	8,397	8,597	8,613	8,628
Scheduled capacity (new)	381	1,307	3,030	3,363	4,081	5,032	5,041	5,758	5,769	5,779
Semi-scheduled equivalent firm capacity (existing)	649	640	652	619	598	559	560	573	574	575
Semi-scheduled equivalent firm capacity (new)	121	312	440	525	516	482	483	494	495	496
Significant non-scheduled equivalent firm capacity (existing)	25	25	26	24	23	22	22	22	22	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	325	321	327	310	429	555	694	806	902	999
Interconnector import capacity (existing)	2,127	2,099	2,136	2,028	1,961	1,832	1,836	1,880	1,883	1,886
Interconnector import capacity (new)	-	143	145	736	711	665	666	682	683	684
Firm (or equivalent) capacity	15,871	16,960	16,479	16,851	17,270	17,522	17,698	18,813	18,942	19,071
Est surplus / deficit	321	1,208	561	575	757	650	543	1,368	1,266	1,205

Table 20 *Infrastructure tender 2 and 3 sensitivity with development delays, EST assessment (MW)*

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Peak demand (sent out)	13,822	14,034	14,284	14,637	14,940	15,318	15,631	15,909	16,148	16,344
Forecast auxiliary at peak	343	333	254	259	194	174	144	156	149	142
Reserve margin	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy security target	15,550	15,752	15,918	16,276	16,514	16,872	17,155	17,445	17,677	17,866
Scheduled capacity (existing)	12,344	12,110	9,697	9,390	9,044	8,376	8,397	8,597	8,613	8,628
Scheduled capacity (new)	248	1,278	1,761	2,922	3,943	5,032	5,041	5,758	5,769	5,779
Semi-scheduled equivalent firm capacity (existing)	654	640	650	628	604	559	560	573	574	575
Semi-scheduled equivalent firm capacity (new)	76	270	426	424	513	482	483	494	495	496
Significant non-scheduled equivalent firm capacity (existing)	26	25	25	25	24	22	22	22	22	23
Significant non-scheduled equivalent firm capacity (new)	-	-	-	-	-	-	-	-	-	-
Demand side participation	328	321	326	315	433	555	694	806	902	999
Interconnector import capacity (existing)	2,144	2,099	2,131	2,060	1,981	1,832	1,836	1,880	1,883	1,886
Interconnector import capacity (new)	-	143	145	747	719	665	666	682	683	684
Firm (or equivalent) capacity	15,819	16,885	15,161	16,512	17,262	17,522	17,698	18,813	18,942	19,071
Est surplus / deficit	**269**	**1,133**	**-757**	**235**	**748**	**650**	**543**	**1,368**	**1,266**	**1,205**