Energy Security Target Monitor Report

November 2021

A report for the New South Wales Minister for Energy

Important notice

PURPOSE

This 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 of the *Energy 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	1/11/2021	Confidential report for the New South Wales Minister for Energy
#2	22/11/2021	Updated report for publication

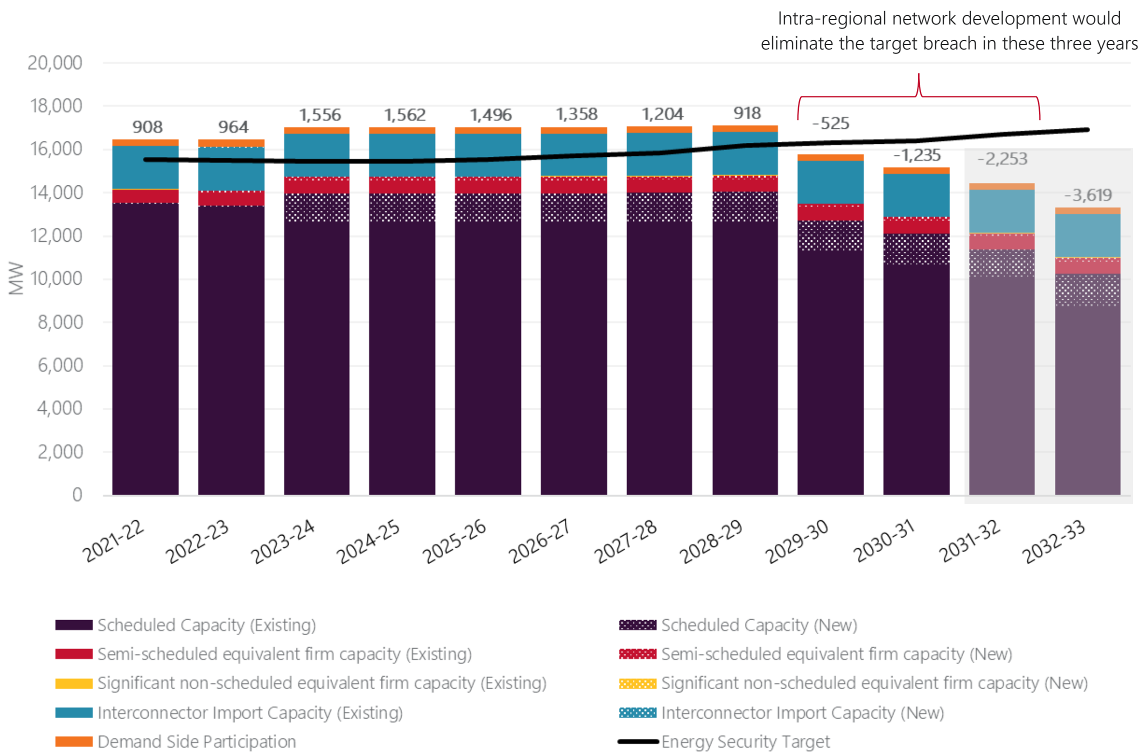
Executive summary

The *Energy Security Target Monitor Report* assesses whether forecast available firm capacity in New South Wales is sufficient to meet the Energy Security Target (EST) defined in the *Electricity Infrastructure Investment Act 2020* (NSW)[1] for each of the next 10 financial years. The EST sets the target firm capacity required to meet 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 projection uses scenarios and inputs from AEMO's 2021 *Electricity Statement of Opportunities* (ESOO)[2], but with some variations and simplifications to express it as a deterministic calculation.

Firm capacity includes the capacity from generation, storage, interconnector, and demand side participation 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 as 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, plus 2031-32 and 2032-33. A target breach is projected from 2029-30.

Figure 1 Central scenario, assessment of the EST, 2021-22 to 2032-33



In calculating the availability of firm capacity AEMO considers limits on major transmission infrastructure between different sub-regions within New South Wales, in accordance with the Electricity Infrastructure

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

[2] See 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.

Investment Regulation 2021[3]. Consideration of these limits leads to approximately 3,000 MW less generation, storage, and imported firm capacity being assumed available to New South Wales electricity customers during peak demand periods.

New transmission developments that increase intra-regional transfer limits into the Sydney-Newcastle-Wollongong area would help alleviate these major transmission constraints and avoid any target breach in the next decade. For example, the commitment of both HumeLink and the Sydney Ring reinforcement projects identified in AEMO's 2020 *Integrated System Plan* (ISP) would unlock access to approximately 2,500 MW of already committed firm capacity from 2027-28, when the Sydney Ring reinforcement is assumed to complete commissioning. To meet these timelines, these network projects would need to progress now.

[3] See https://legislation.nsw.gov.au/view/html/inforce/current/sl-2021-0102, amended with effect from 12 November 2021 by the Electricity Infrastructure Investment Amendment (Safeguard) Regulation 2021 (nsw.gov.au). All references in this report to the EII Regulation are to that regulation as amended on 12 November 2021.

Contents

Tables

Figures

1. Introduction

The New South Wales Government has set a New South Wales Energy Security Target (EST) to ensure the state takes appropriate action to maintain a reliable electricity supply over the medium to long term.

The EST is defined in Part 3 of the *Electricity Infrastructure Investment Act 2020 (NSW)*[4] (the EII Act). The EST is set at the capacity level needed to meet forecast maximum customer demand during summer while maintaining a reserve margin to account for the unexpected loss of two of the region's largest available generating units:

Energy Security Target = maximum demand + reserve margin

where maximum demand is based on a 10% probability of exceedance (POE) forecast.

Part 3 of the EII Act also defines the role of the "energy security target monitor", a role that AEMO is undertaking in 2021.

As EST monitor, AEMO forecasts the EST and reports on any projected breach of the EST (target breach) for each of the next 10 financial years, in accordance with the EII Act and the Electricity Infrastructure Investment Regulation 2021[5] (the EII Regulation).

This *EST monitor report* details this assessment.

For the purposes of section 14(3) of the EII Act, in AEMO's opinion, the 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.

2. Inputs and assumptions

For this EST assessment, AEMO has adopted inputs and assumptions used to produce the 2021 *Electricity Statement of Opportunities* (ESOO)[6] and/or other relevant assumptions from AEMO's 2021 *Inputs Assumptions and Scenarios Report* (IASR)[7], unless otherwise stated. Key assumptions are outlined below.

2.1 Maximum demand

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

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

[5] See https://legislation.nsw.gov.au/view/html/inforce/current/sl-2021-0102, amended with effect from 12 November 2021 by the Electricity Infrastructure Investment Amendment (Safeguard) Regulation 2021 (nsw.gov.au). All references in this report to the EII Regulation are to that regulation as amended on 12 November 2021.

[6] See 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.

[7] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

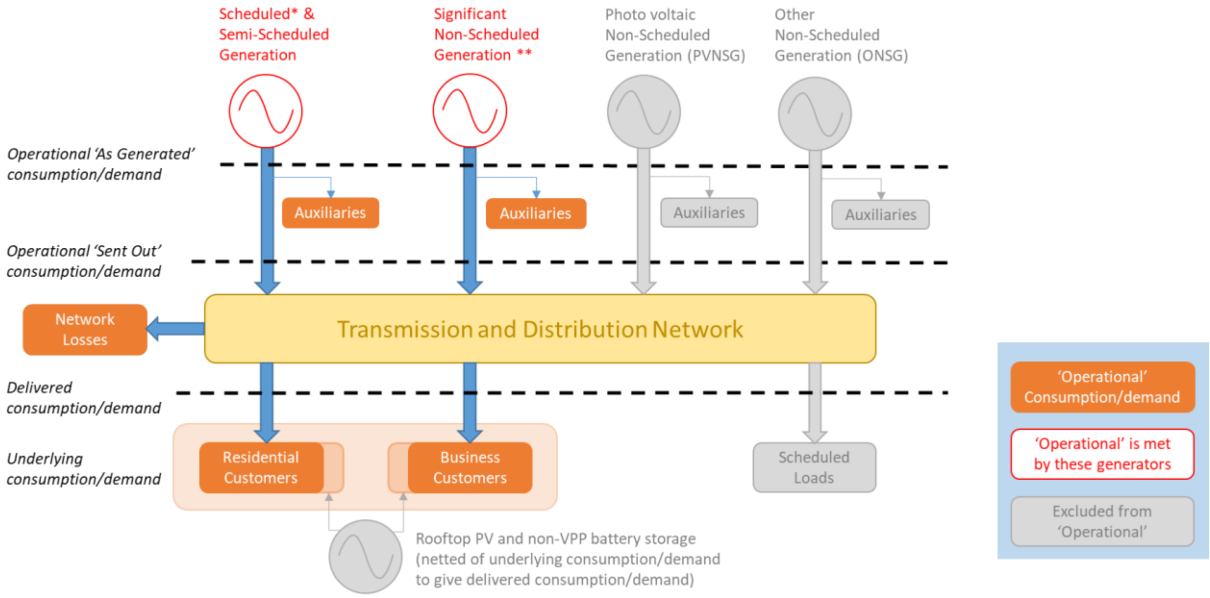
- Takes into account the most recent forecast of maximum demand for sent out generation in New South Wales in summer, as published by AEMO in the 2021 ESOO, and
- Includes the forecast of generating unit auxiliaries as forecast by AEMO in the 2021 ESOO to reflect the maximum demand as generated by generating units in New South Wales in summer.
- Takes into account the forecast of use of distributed energy resources (DER) in New South Wales, as specified in the 2021 ESOO.

AEMO's most recent 10% POE maximum operational 'as generated' demand forecast for New South Wales is adopted as the maximum demand for each corresponding year of the EST assessment.

- Maximum operational demand means the highest level of electricity drawn from the grid at any one time in a financial year.
- In the demand forecasts used in the 2021 ESOO, maximum operational demand occurs in summer in New South Wales for each of the forecast financial years.
- Operational 'as generated demand' refers to the electricity used by residential, commercial, large industrial consumers, and generator auxiliary loads, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units (including storage) (see Section 2.2).
- The 10% POE forecast implies that the forecast is expected to be exceeded once in every 10 years.

Figure 2 explains AEMO's demand definitions. Further detail is provided in AEMO's 2021 ESOO[8].

Figure 2 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.

The demand forecasts used to assess the EST were developed for the 2021 ESOO and incorporate assumptions around continued investments in energy efficiency activities, increases in DER such as distributed photovoltaic (PV) systems and battery storage, and projected generator auxiliary load.

Further changes to the New South Wales Energy Savings Scheme in December 2020[9] were captured within the demand forecasts and are therefore implicitly considered in the EST assessment. This includes the energy

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[8] See Section 1.2 of https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf?la=en&hash=D53ED10E2E0D452C79F97812BDD926ED for further detail regarding demand definitions and forecasts.

[9] See https://www.legislation.nsw.gov.au/view/html/inforce/current/act-1995-094#sch.5.

efficiency component of the Peak Demand Reduction Scheme (PDRS). This inclusion is consistent with AEMO's approach to demand modelling, whereby the best forecast of energy efficiency considering state and federal policies is developed per scenario. Unlike the energy efficiency component, the demand side participation (DSP) component of the PDRS is not considered in the forecast, because there are not yet any committed DSP projects under the scheme (see DSP section below).

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 matches AEMO's definition of operational demand, which is demand supplied by these generating units (see Figure 2). Firm capacity for an EST forecast year should also include forecast interconnector capacity, demand response, and DSP.

This section describes how AEMO has determined each of these elements of the firm capacity calculation, including how major constraints on transmission infrastructure within New South Wales have been taken into account.

Existing scheduled generation and storage capacity

The firm capacity of scheduled generators and storage is taken as the summer peak rating for each unit from the October 2021 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.

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
- 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 10% POE 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:

- Observed aggregate semi-scheduled capacity factors (generation as a proportion of total capacity) for wind and solar generators on all days during the last three summers (2018-19, 2019-20, and 2020-21) that exceeded daily operational 'as generated' maximum demand of 12,500 megawatts (MW), thereby only capturing very high demand days.
- The 10th percentile of these observed aggregate capacity factors (meaning that 90% of observed aggregate capacity factors exceeded this percentile). Figure 3 shows this for numerous intervals of interest.

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

Figure 3 10th percentile capacity factors for identified summer days

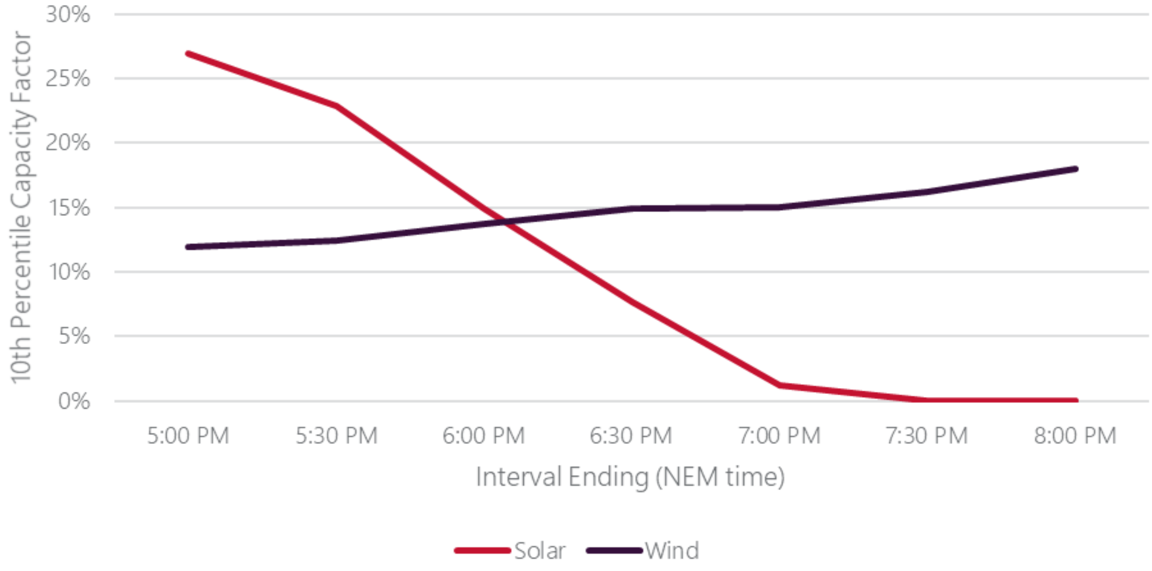
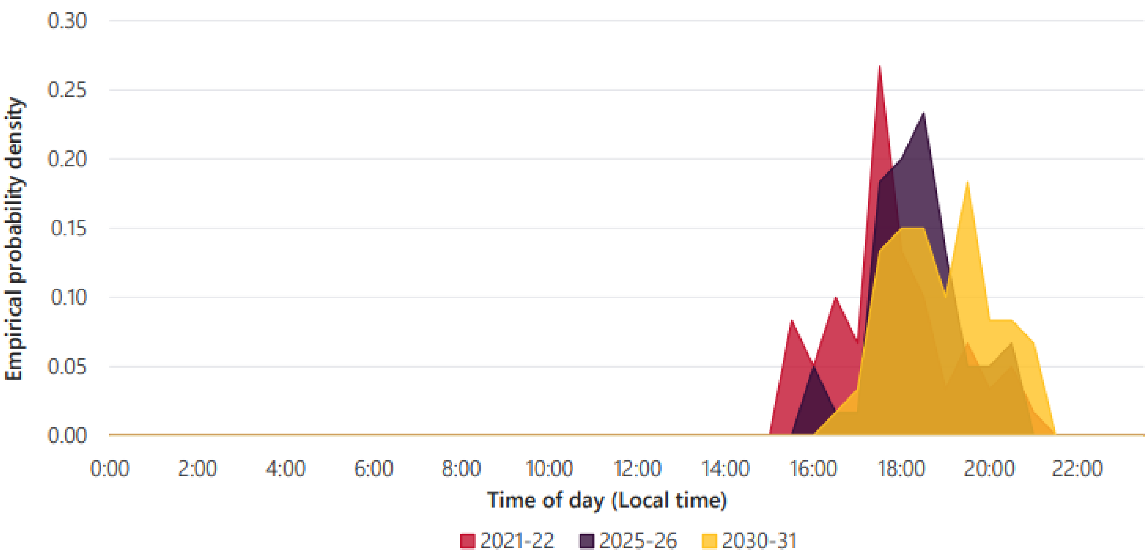


Figure 4 shows the probability distribution of maximum demand for New South Wales summer in local time. While some time-shifting is forecast over the 10-year horizon, uncertainty in the timing of maximum demand remains substantial.

For the purposes of the EST, AEMO has selected the 6:00 pm National Electricity Market (NEM) time (7:00 pm local daylight savings time) interval to represent the maximum demand interval for the entire forecast horizon. Any changes to semi-scheduled equivalent firm capacity observed over the horizon is therefore driven by new capacity, rather than changes to the timing of maximum demand.

Figure 4 Central forecast showing change in distribution of time of 50% POE summer maximum demand in New South Wales, 2021-22 to 2030-31



Based on the above assumptions, the peak contribution factor applied in this 2021 *EST Monitor Report* is estimated to be 13.7% for wind and 14.9% for solar. These capacity factors are applied to the Summer Typical capacity from the October 2021 Generation Information publication[11] to determine the available equivalent firm capacity of existing semi-scheduled generators.

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 is 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

Generator closures

Expected closure years for all existing generators in the Central, Slow Change and Hydrogen Superpower scenarios are taken from the October 2021 Generating unit expected closure year publication[11]. Unit closure is assumed to occur after summer for the year specified; for example, Vales Point B, which is expected to close in 2029, is considered available for the 2028-29 summer, and unavailable for the entire 2029-30 summer.

It was noted in the 2021 ESOO that the exit of coal-fired and some gas-fired generation may occur sooner than currently reported. The Early Coal Retirements sensitivity aims to test the implications of an accelerated exit of coal on reliability outcomes. In the Early Coal Retirements sensitivity, both units of Vales Point B Power Station were assumed to retire prior to summer 2027-28 and Eraring Power Station units were assumed to retire according to the following schedule: Unit 4 prior to summer 2028-29, Unit 1 prior to summer 2029-30, and Units 2 and 3 prior to summer 2030-31.

Proposed generation and storage projects

The EII Regulation, clause 14(2), 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*'[13] in the October 2021 Generation Information publication, including the Snowy 2.0 pumped hydro project (2,040 MW) and Kurri Kurri gas peaking plant (750 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, due to advice from the Department that suggests they are insufficiently advanced.

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[11] See https://www.aemo.com.au/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.

[13] 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

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

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
Transgrid's Wallgrove Grid Battery	In advance of 2021-22 summer	50	Yes
CWP Renewables' Sapphire Battery Facility	In advance of 2022-23 summer	30	Yes
UPC/AC Renewables Australia's New England Solar Farm Battery	In advance of 2023-24 summer	50	Yes
EnergyAustralia's Tallawarra B	In advance of 2023-24 summer	316	Yes
Darlington Point Battery Energy Storage System (BESS)	In advance of 2023-24 summer	200	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.

Existing and proposed interconnector capacity

Interconnector import capacity, assumed to be operating under normal conditions, also contributes to firm capacity in the calculation of the EST. This includes firm capacity from the following proposed interconnector augmentations, if AEMO considers the capacity likely to be available to New South Wales electricity customers in the financial year:

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 2021 IASR 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 (in 2021-22) 1,205 (from 2022-23 once QNI minor fully commissioned and tested)
VIC – SNSW ("VNI")	700 (before 2023-24) 870 (from 2023-24 once VNI minor fully commissioned and tested)
SNSW – SA ("Project EnergyConnect")	800 (from 2025-26 once PEC fully commissioned and tested)

Source: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx.

The timing differences in Table 3 reflect the following proposed interconnector augmentations for which a revenue determination has been made:

- **Queensland New South Wales Interconnector (QNI) Minor by July 2022**. Involves uprating of Liddell – Tamworth, Liddell – Muswellbrook, and Muswellbrook – Tamworth 330 kilovolt (kV) transmission lines, installation of shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations, and installation of dynamic reactive plant at Tamworth and Dumaresq.
- **Victoria New South Wales (VNI) Minor by September 2023.** Involves uprating of the South Morang – Dederang 330 kV line, installation of an additional 500/330 kV transformer at South Morang, and the addition of power flow controllers on the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV lines.
- **Project EnergyConnect (PEC) by June 2025.** Involves construction of new double-circuit 330 kV transmission lines between Robertstown, Buronga, Dinawan, and Wagga Wagga, and an additional 220 kV line between Red Cliffs and Buronga. It has completed its regulatory approval process and received expenditure approval from the Australian Energy Regulator (AER) in May 2021. To allow for inter-network testing, PEC has been modelled with its full capacity available from June 2025.

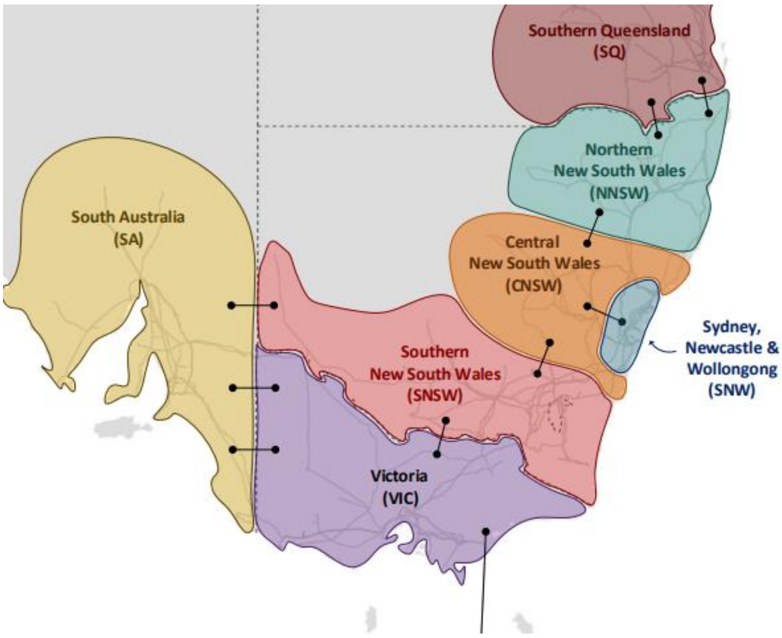
Major intra-regional transmission limits

Major constraints on intra-regional transmission infrastructure 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 is used to estimate the major network constraints. The key New South Wales sub-regions represented in the 2021 IASR are highlighted in Figure 5, of which two are used in the 2021 EST assessment to 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 5 Sub-regional model as documented in the IASR



To test whether these major transmission limits impact the EST, AEMO first assesses the EST against each relevant sub-region separately. It is 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 than the whole of the New South Wales target surplus/breach, the difference is assessed as the impact of the major intra-regional transmission limit. If major intra-regional transmission limits are identified, proposed firm capacity forecast to connect is 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 is 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 is 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 2021 assessment, only proposed firm capacity is 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 sub-regional 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[14], summarised in Table 4.

[14] 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.

- Auxiliaries are assumed as a ratio of maximum potential zonal aggregate auxiliaries to the maximum potential regional aggregate auxiliaries[15].
- Reserves are 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.

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

	CNSW + SNW	SNW
2021-22	11,874	10,705
2022-23	11,805	10,598
2023-24	11,748	10,553
2024-25	11,742	10,512
2025-26	11,801	10,563
2026-27	11,917	10,670
2027-28	12,048	10,791
2028-29	12,311	11,026
2029-30	12,411	11,102
2030-31	12,471	11,173

Table 5 Import capabilities between sub-regions at peak demand

Intra-regional limit	Intra-regional import capability (MW)
SNSW –> CNSW	2,700
NNSW –> CNSW	930
CNSW –> SNW	6,125 + 0.33 * (Eraring+Vales Point) generation MW

Source: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en.

Demand response and demand side participation

Demand response and DSP are both considered as firm capacity in the calculation of the EST and are both considered in AEMO's DSP forecast, as published in the 2021 ESOO. The amount of DSP assumed is consistent with the AEMO 2021 ESOO, where only existing and committed DSP projects were considered.

The contribution of DSP is estimated to be 308 MW in New South Wales for all years in the projection, incorporating both price- and reliability-driven DSP responses. As the majority of DSP in New South Wales is

[15] 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.

located in the Sydney-Newcastle-Wollongong sub-region, the contribution of DSP is assumed to be 308 MW for each sub-regional assessment, where applicable.

No increases to DSP have been made in consideration of the PDRS within the time horizon of the EST calculation, consistent with AEMO's DSP forecasting methodology and definition of committed projects[16]. Despite the energy efficiency component of the PDRS being considered in the demand forecast, the approach to exclude the DSP component of the PDRS is applied consistently with other supply side solutions that consider only existing and committed developments. This methodology specifies that DSP is only considered committed if they are:

- reported through the DSP Information Portal as qualifying contracts under the Retailer Reliability Obligation (RRO), or
- an approved Demand Management Incentive Scheme (DMIS) initiative under the Australian Energy Regulator's (AER's) revenue reset process, or
- other initiatives providing a similar level of certainty of the DSP progressing.

Generator auxiliary load

The generator auxiliary load forecasts developed for the ESOO were calculated at a regional level over a 10-year period and are published in the forecasting portal[17]. As the 2031-32 and 2032-33 financial years fall outside of this period, the generator auxiliary load forecast for these years was calculated as follows:

- Auxiliary rates published in the IASR were multiplied by the available capacity for each scheduled generator, then summed.
- The summed auxiliary load was then scaled such that the calculation is consistent with the published auxiliary rate forecast for 2030-31.

For the purposes of the sub-regional EST calculation, the generator auxiliary load forecasts used in the CSNW + SNW and SNW sub-regional assessments were assumed to be proportional to the maximum potential generator auxiliaries within each sub-region, compared to the maximum potential generator auxiliaries for New South Wales and the ESOO forecast.

Fixed hydrogen load

The maximum operational as generated demand forecast includes the fixed load component of hydrogen electrolysers in applicable scenarios. AEMO assumed the flexible load component would not be consuming during periods of peak demand. Over the period assessed, hydrogen electrolyser load is only present in the Hydrogen Superpower scenario from the 2029-30 financial year. It is 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.

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

	Unit 1	Unit 2	Reserve
2021-22	MP1	ER02	1,385
2022-23	MP1	ER01	1,385

[16] See: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

[17] See forecasting.aemo.com.au/.

	Unit 1	Unit 2	Reserve
2023-24	MP1	ER01	1,385
2024-25	MP1	ER02	1,385
2025-26	MP1	ER02	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

The two largest generating units in New South Wales in 2021-22 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). After 2021-22, the Eraring units progressively decrease their summer ratings. While MP1 continues to be one of the two largest generators, the decreases in the ratings of the Eraring units result in the second unit switching between Eraring Power Station Units 1 and 2, and from 2026-27 the Mount Piper Power Station 2 (MP2) becomes the second largest unit.

3. Scenarios and sensitivities

In consultation with industry and consumer groups, AEMO developed several scenarios and additional sensitivities for use in its 2021-22 forecasting and planning publications, including the 2021 ESOO, and these scenarios and assumptions are documented in detail in the 2021 IASR.

In preparing a report under the EII Regulation, 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 2021 ESOO, as applicable to New South Wales. These are summarised in Table 7 below.

Table 7 Descriptions of scenarios and sensitivities for the EST assessment

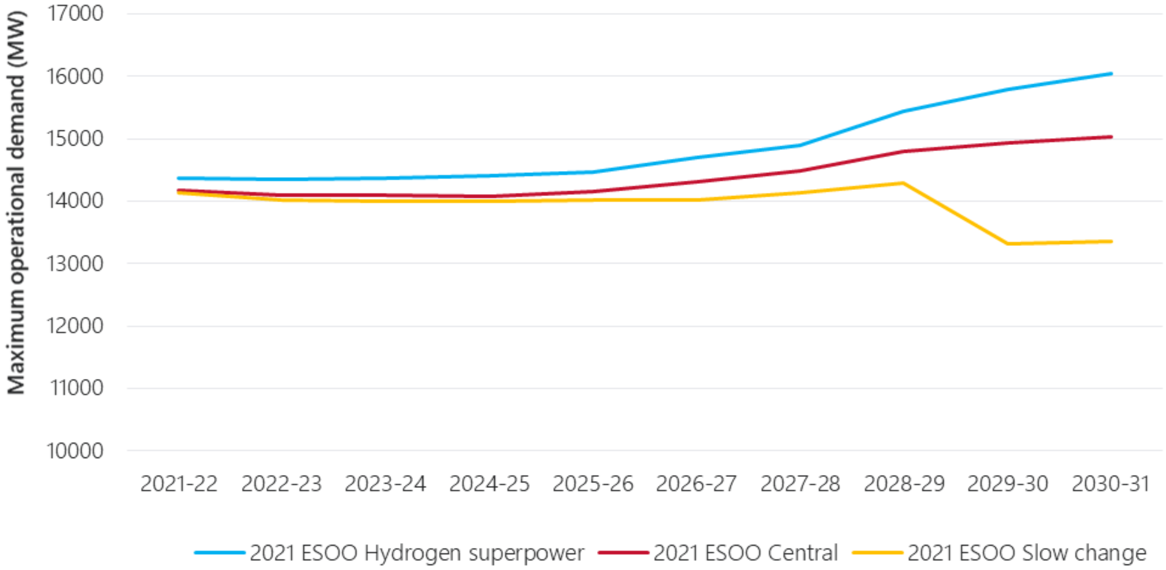
ESOO scenario	Scenario description
Slow Change	Challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures, slower decarbonisation action, and consumers proactively managing energy costs through continued investments in DER, particularly distributed PV.
ESOO Central	Future driven by existing government policy commitments in the next 10 years, continuation of current trends in consumer investments such as DER and corporate emission abatement, and technology cost reductions. The ESOO Central scenario reflects the first 10 years of both the Net Zero 2050 scenario and the Steady Progress scenario reports in AEMO's IASR; these scenarios are identical over the next decade.
Hydrogen Superpower	Strong global action towards emissions reduction, with significant technological breakthroughs and social change to support low and zero emissions technologies. Emerging industries such as hydrogen production present unique opportunities for domestic developments in manufacturing and transport, and renewable energy exports via hydrogen become a significant part of Australia's economy. New household connections tend to rely on electricity for heating and cooking, but those households with existing gas connections progressively switch to using hydrogen – first through blending, and ultimately through appliance upgrades to use 100% hydrogen.
Early Coal Retirements sensitivity (applied to the ESOO Central scenario)	To test the implications of an accelerated exit of coal on reliability outcomes, AEMO developed a sensitivity where all coal-fired power stations are assumed to retire two years earlier than the currently provided expected closure year (excluding Liddell Power Station, which is within its three-year notice of closure period).

For the purpose of the EST calculation, only the maximum demand forecasts vary between each of the three scenarios – the firm capacity remains unchanged. Figure 6 shows the 10% POE maximum demand forecasts to be adopted for each of the three scenarios.

No components relating to hydrogen industries are included in the maximum operational demand forecasts presented below, because these will be presented in future versions of the demand forecasts as an outcome of AEMO's long-term modelling for the 2022 *Integrated System Plan* (ISP).

In the Early Coal Retirements sensitivity, both units of Vales Point B Power Station were assumed to retire prior to summer 2027-28 and Eraring Power Station units were assumed to retire according to the following schedule: Unit 4 prior to summer 2028-29, Unit 1 prior to summer 2029-30, and Units 2 and 3 prior to summer 2030-31.

Figure 6 New South Wales 10% POE maximum demand forecast, operational 'as generated', in MW across scenarios



4. EST assessment

All scenarios and sensitivities have been assessed with consideration for major constraints on transmission infrastructure across different sub-regions of New South Wales consistent with the EII Regulation, and the inputs and assumptions listed in this report. Where firm capacity has been discounted due to major constraints on transmission infrastructure, further analysis is also provided to demonstrate how development of key network projects currently under consideration would improve the EST outlook.

The results of this assessment are discussed in this section.

The assessment charts show the 10-year EST outlook, plus 2031-32 and 2032-33 (the additional two years are greyed to denote that they are outside the 10-year EST outlook period).

Central scenario

In the Central scenario, 10% POE maximum demand is forecast to remain steady, then to rise in the second five years of the horizon, driven by a return to growth of the business mass market consumer segment, and an increase in the rate of electrification (fuel switching from other fuels to electricity). Auxiliaries at time of peak are forecast to decline, following the expected exit of numerous coal-fired generators, as noted in the previous section. The reserve margin reduces from 1,385 MW to 1,380 MW over the horizon.

Collectively these components sum to the EST, as shown in Figure 7.

Figure 7 Central scenario, EST components

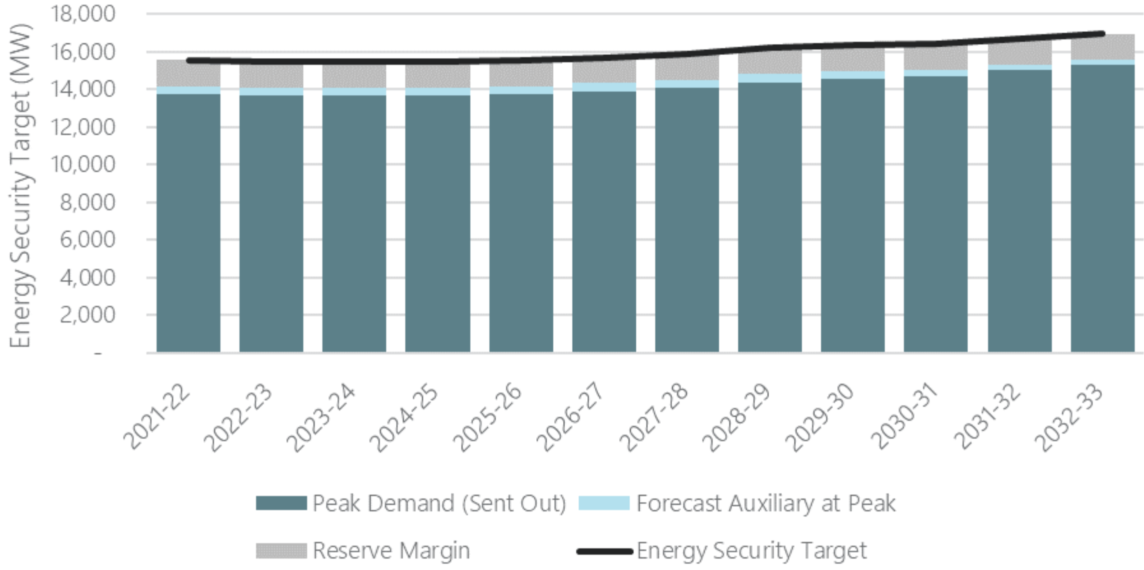
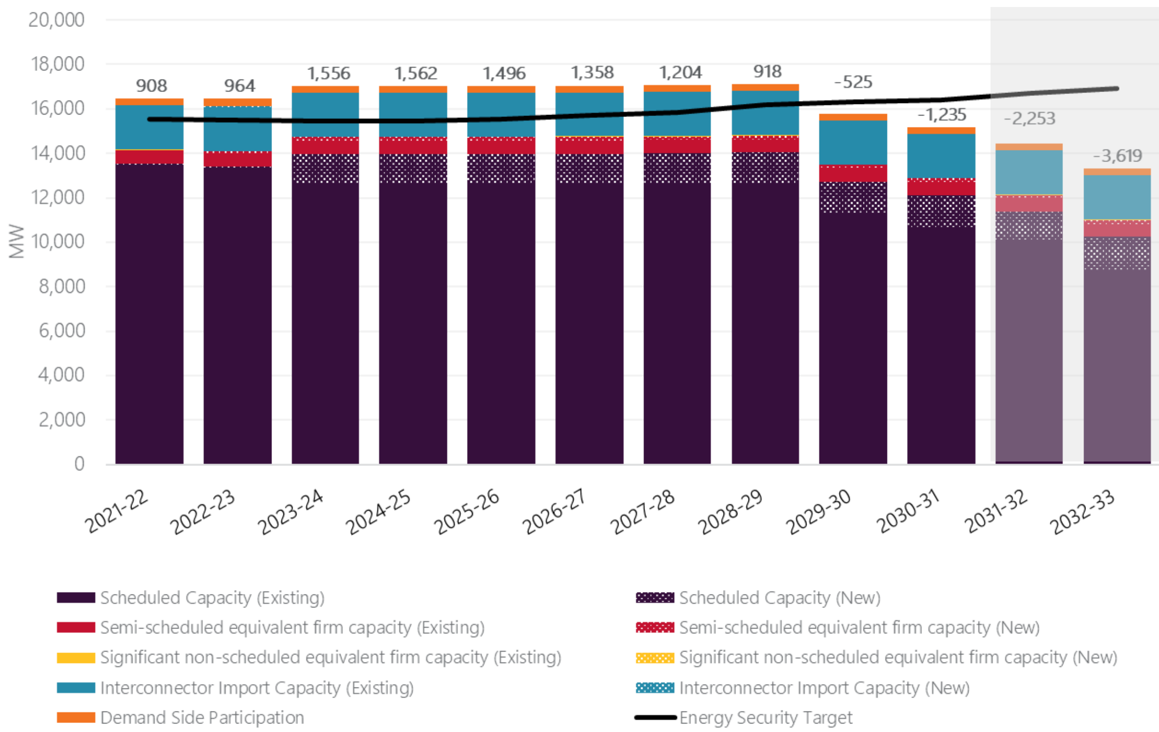


Figure 8 shows the assessment of the EST for the Central scenario, with a target breach identified from 2029-30. This is due to major transmission infrastructure constraints limiting the ability for existing and proposed firm capacity to be available to the majority of New South Wales electricity customers in Central New South Wales, Sydney, Newcastle and Wollongong.

Figure 8 Central scenario, assessment of the EST, 2021-22 to 2032-33



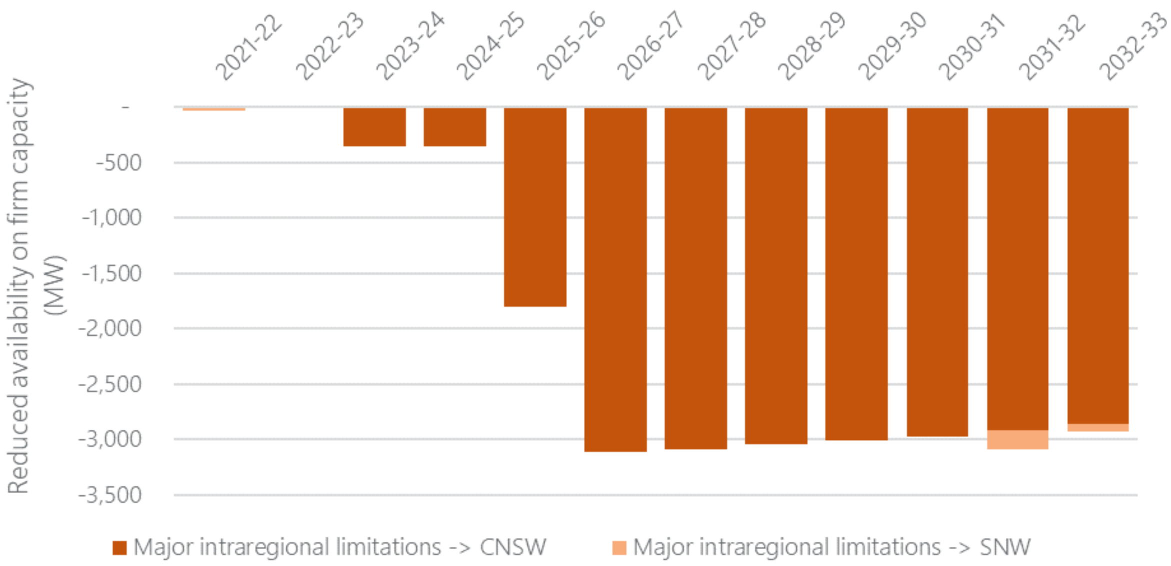
Key considerations in, and observations from, the assessment include:

- 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 more than offset by the commitment of new scheduled generation within the SNW sub-region, including Kurri Kurri and Tallawarra B power stations.
- Proposed interconnector import capacity is expected to become available over the horizon, including QNI Minor (2022-23), VNI Minor (2023-24), and PEC (2025-26). However, forecast major constraints on intra-regional transmission infrastructure between the outer and inner sub-regions of New South Wales, as shown in Error! Reference source not found.Figure 9, are expected to constrain this proposed capacity from being available to consumers in the CNSW and SNW sub-regions during peak demand periods. As such, this proposed capacity is almost entirely 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) project. However, forecast major constraints on intra-regional transmission infrastructure between the outer and inner regions of New South Wales are expected to constrain this proposed capacity from being available to consumers in the CNSW and SNW sub-regions during peak demand periods. As such, this proposed capacity is mostly discounted over the entire horizon.
- A target breach is forecast from 2029-30, when scheduled generators (Vales Point and Eraring power stations) in the SNW and CNSW sub-regions retire. At this point, firm capacity from outside these sub-regions would be required to meet demand in peak periods, but cannot be made available to the majority of New South Wales customers due to forecast constraints on intra-regional transmission infrastructure.

Figure 9 shows the projected reduction in generation, storage, and interconnector firm capacity due to these major constraints on intra-regional transmission infrastructure in this assessment.

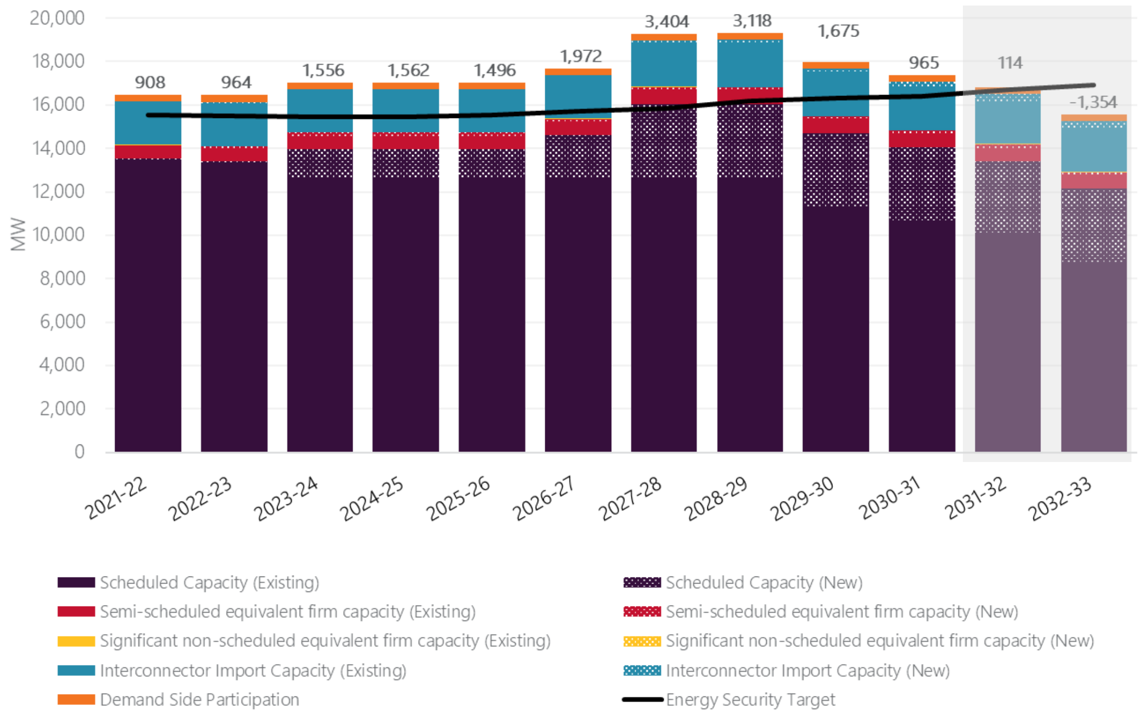
Figure 9 Central scenario, estimated impact of major transmission limits on firm capacity, 2021-22 to 2032-33



The projected target breach forecast from 2029-30 under this assessment would be eliminated by the commitment of new transmission developments that increase intra-regional transfer limits from SNSW to CNSW and from CNSW to SNW. If HumeLink and the Sydney Ring reinforcement projects identified in AEMO's 2020 ISP were committed, they would unlock access to approximately 2,500 MW of already committed firm generation and storage capacity. As a result, the EST would be in surplus until 2032-33 when all of the Eraring and Vales Point units have closed (see Figure 10). At this point, other new firm generation and storage capacity would be needed in New South Wales, such as the investments proposed in the New

South Wales Electricity Infrastructure Roadmap. Neither network project on its own is projected to entirely eliminate the forecast target breach over the 10-year outlook.

Figure 10 Central scenario, assessment of the EST with HumeLink and Sydney Ring reinforcement projects included, 2021-22 to 2032-33



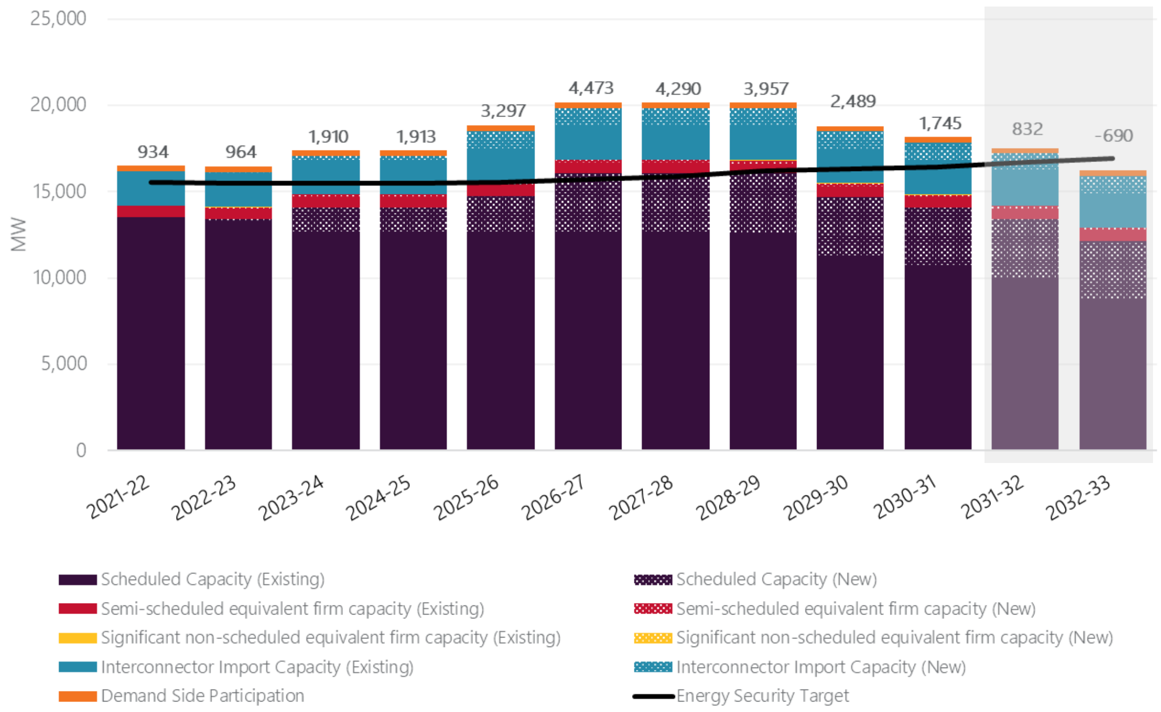
In the absence of network development, other potential solutions to mitigate the projected target breach from 2029-30 include:

- The commitment of new generation or storage capacity in the SNW region.
- The commitment of new DSP.

The EII regulations were amended on the 12th November 2021[18] specifying that the energy security target monitor may take into account major constraints on transmission infrastructure across different sub-regions of New South Wales. For the purpose of maintaining continuity with previous versions of the regulation, an EST calculation without consideration for these transmission infrastructure limitations is shown in Figure 11. The main difference between this figure and Figure 10 is that proposed interconnector import capacity from PEC, QNI minor and VNI minor is no longer discounted due to constraints on transmission infrastructure within New South Wales. The calculation shows that a target breach first occurs in 2032-33, confirming that intra-regional transmission limits, rather than firm capacity shortfalls drive the target breach under the calculation consistent with the current regulations.

[18] See https://legislation.nsw.gov.au/view/html/inforce/current/sl-2021-0102, amended with effect from 12 November 2021 by the Electricity Infrastructure Investment Amendment (Safeguard) Regulation 2021 (nsw.gov.au). All references in this report to the EII Regulation are to that regulation as amended on 12 November 2021.

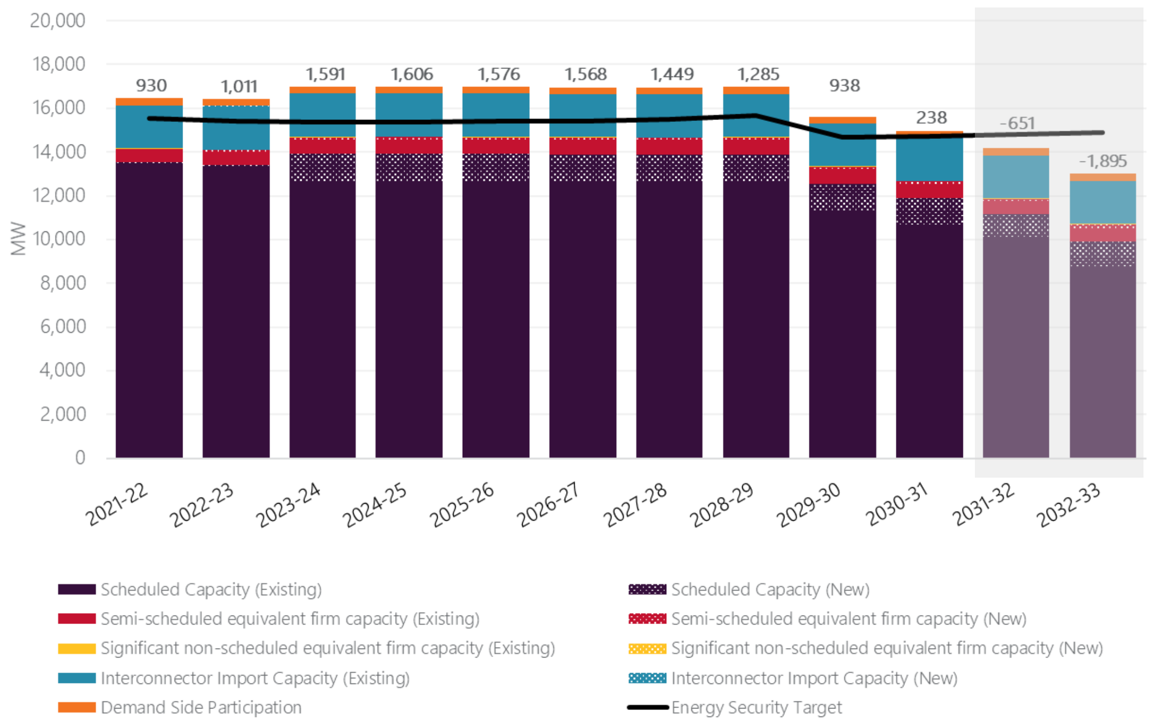
Figure 11 Central scenario, assessment of the EST consistent with the previous version of the EII regulations, 2021-22 to 2032-33



Slow Change scenario

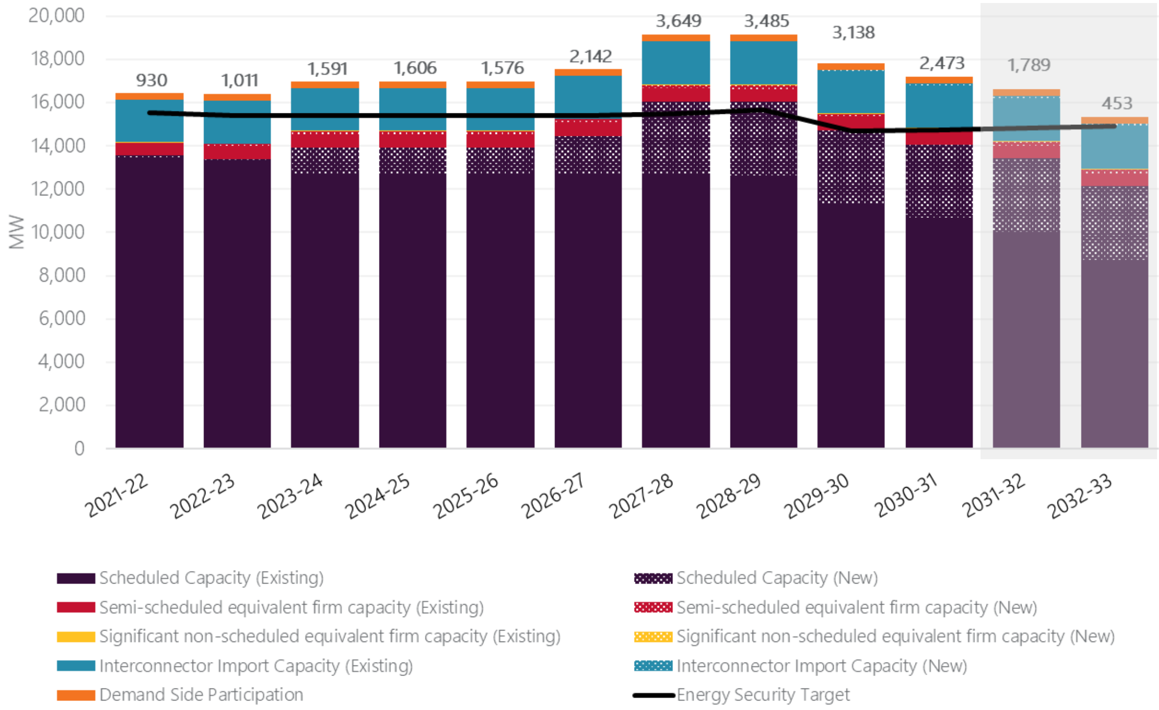
The EST assessment for the Slow Change scenario is shown in Figure 12. The lower demand assumptions delay the target breach until 2031-32, when all four Eraring units have retired (outside the 10-year outlook period). Key observations and solutions to mitigate the indicative target breach in that year are the same as the Central scenario.

Figure 12 Slow Change scenario, assessment of the EST, 2021-22 to 2032-33



The projected firm capacity shortfall from 2031-32 under this assessment would be eliminated by the commitment of HumeLink and the Sydney Ring reinforcement projects (see Figure 13).

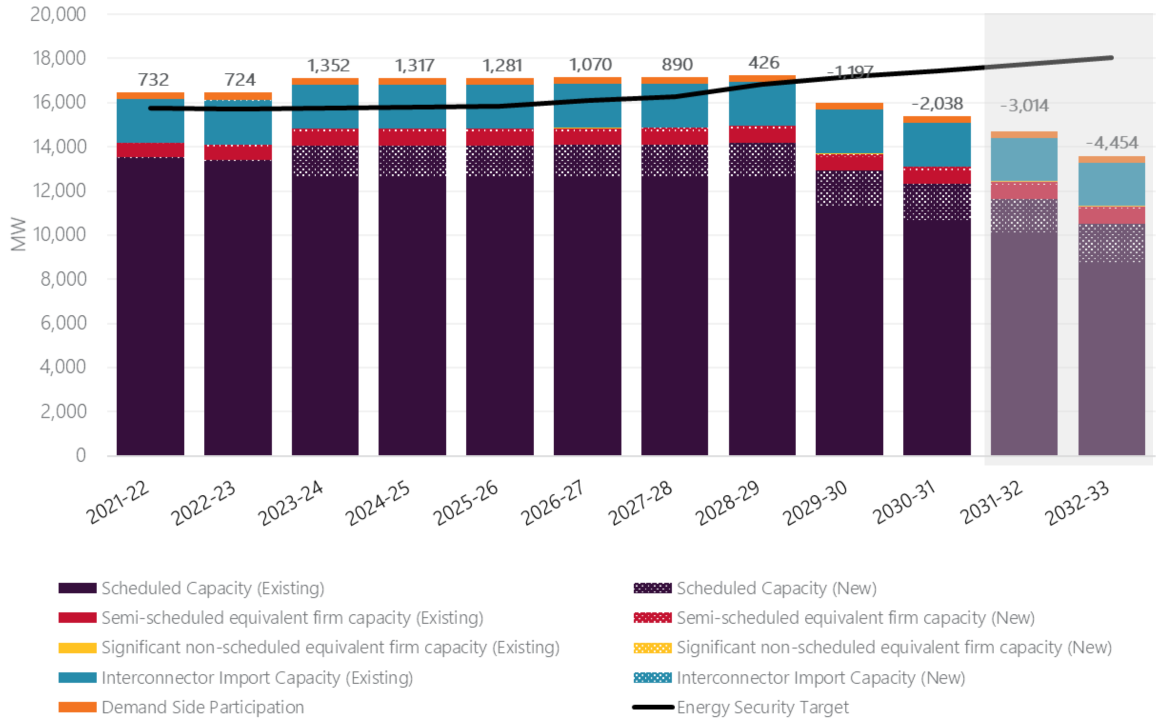
Figure 13 Slow Change scenario, assessment of the EST with HumeLink and Sydney Ring reinforcement projects included, 2021-22 to 2032-33



Hydrogen Superpower scenario

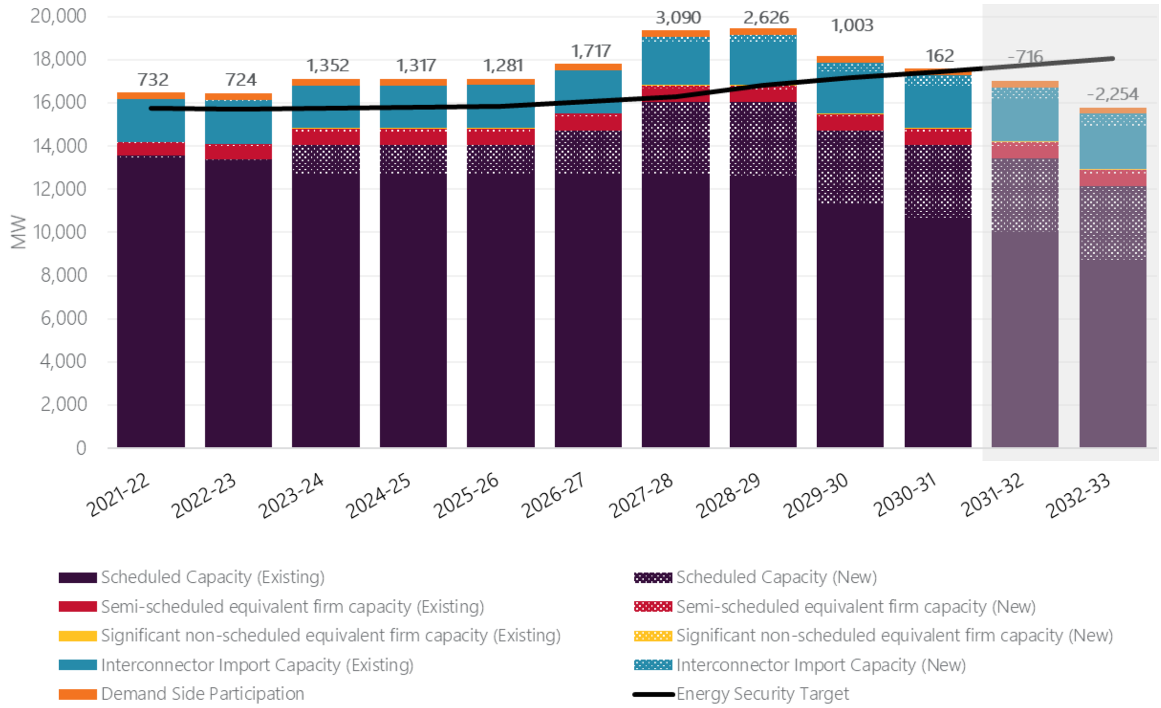
The EST assessment for the Hydrogen Superpower scenario is shown in Figure 14. The higher demand assumptions result in a larger target breach from 2029-30. Key observations and solutions to mitigate the forecast target breach remain the same as the Central scenario, however the larger size of the breach indicates an increased need for additional firm capacity in this scenario.

Figure 14 Hydrogen Superpower scenario, assessment of the EST, 2021-22 to 2032-33



The projected target breach forecast from 2029-30 under this assessment would be eliminated by the commitment of new transmission developments that increase intra-regional transfer limits from SNSW to CNSW and from CNSW to SNW. If HumeLink and the Sydney Ring reinforcement projects identified in AEMO's 2020 ISP were committed, the EST would be in surplus until 2031-32 when the majority of the Eraring and Vales Point units have closed (see Figure 15). At this point, other new firm generation and storage capacity would be needed in New South Wales, such as the investments proposed in the New South Wales Electricity Infrastructure Roadmap.

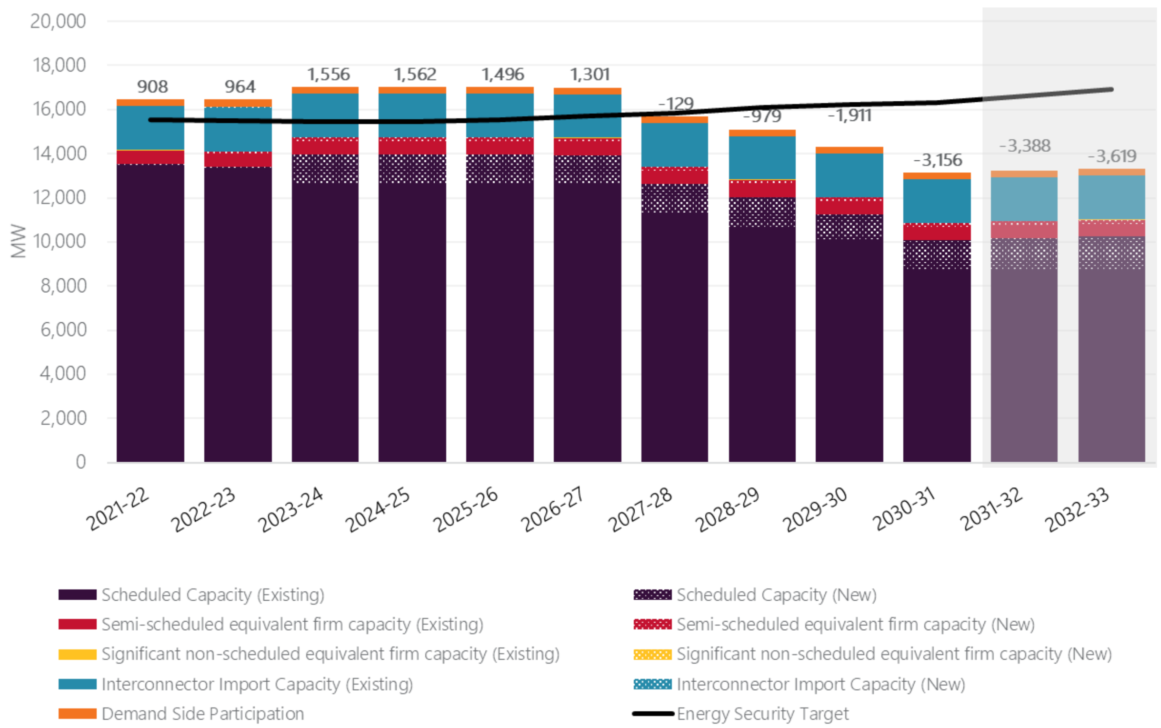
Figure 15 Hydrogen Superpower scenario, assessment of the EST with HumeLink and Sydney Ring reinforcement projects included, 2021-22 to 2032-33



Early Coal Retirements sensitivity

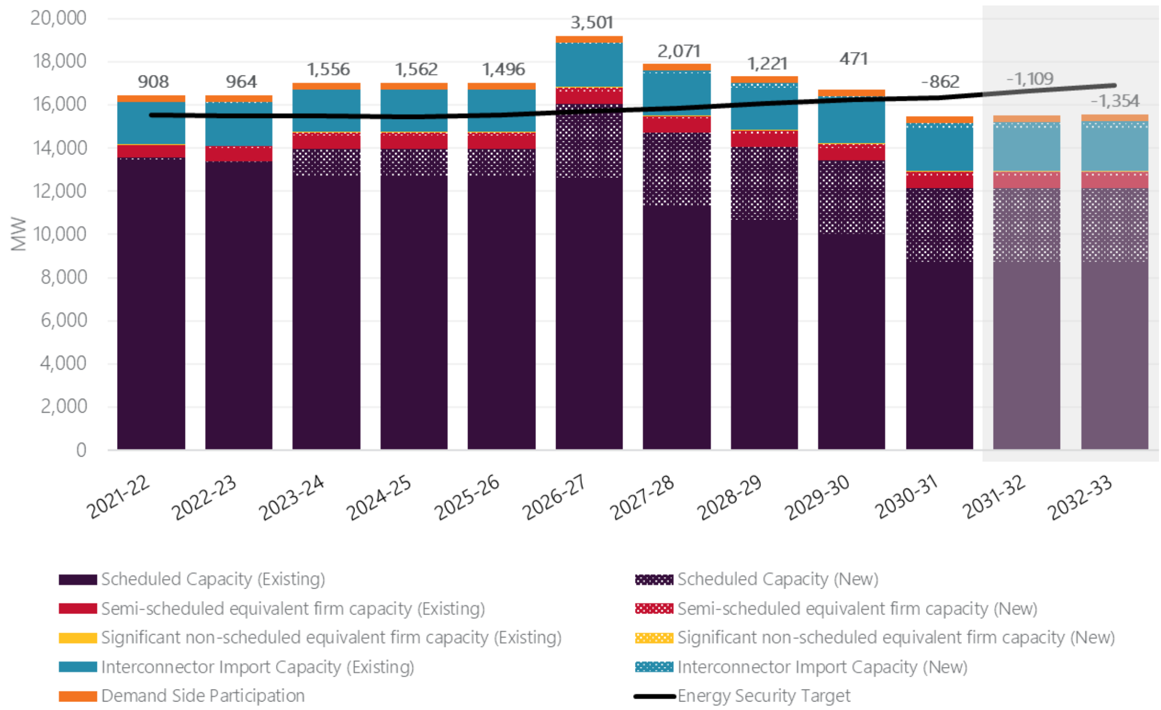
The EST assessment for the Early Coal Retirements sensitivity is shown in Figure 16. Consistent with the earlier retirement of key coal-fired generator units, the forecast target breach begins earlier, in 2027-28, and increases until 2030-31. Key observations and solutions to mitigate the forecast target breach remain the same as the Central scenario, but the timing represents an earlier need for additional firm capacity.

Figure 16 Early Coal Retirements sensitivity, assessment of the EST, 2021-22 to 2032-33



Under this sensitivity, a target breach is still forecast in the next decade, even if HumeLink and the Sydney Ring reinforcement projects were committed, but only in the last year (see Figure 17). At this point, other new firm generation and storage capacity would be needed in New South Wales, such as the investments proposed in the New South Wales Electricity Infrastructure Roadmap, or more network augmentation would be needed to increase the ability for firm interconnector capacity to reach the major New South Wales customers.

Figure 17 Early Coal Retirements sensitivity, assessment of the EST with HumeLink and Sydney Ring reinforcement projects included, 2021-22 to 2032-33



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 MW) 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[19] 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.

As there are numerous target breaches forecast in the 10-year outlook period, the duration is calculated for these years below.

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

Central scenario, 2029-30

A target breach of 525 MW has been forecast for the 2029-30 financial year in the Central scenario and is associated with a demand threshold of 14,030 MW. The following figures show the results of this breach analysis:

- Figure 18 shows the monthly distribution of the periods that exceed the demand threshold. The incidents only occurred in summer.
- Figure 19 shows the projected frequency of incidents per year, with all reference years indicating a maximum of three events per year under 10% POE summer demand conditions, and no events under 10% POE winter demand conditions.
- Figure 20 shows the projected incident duration, with summer incidents up to four and a half hours in duration.

Figure 18 Projected incident frequency by forecast month, Central scenario, 2029-30

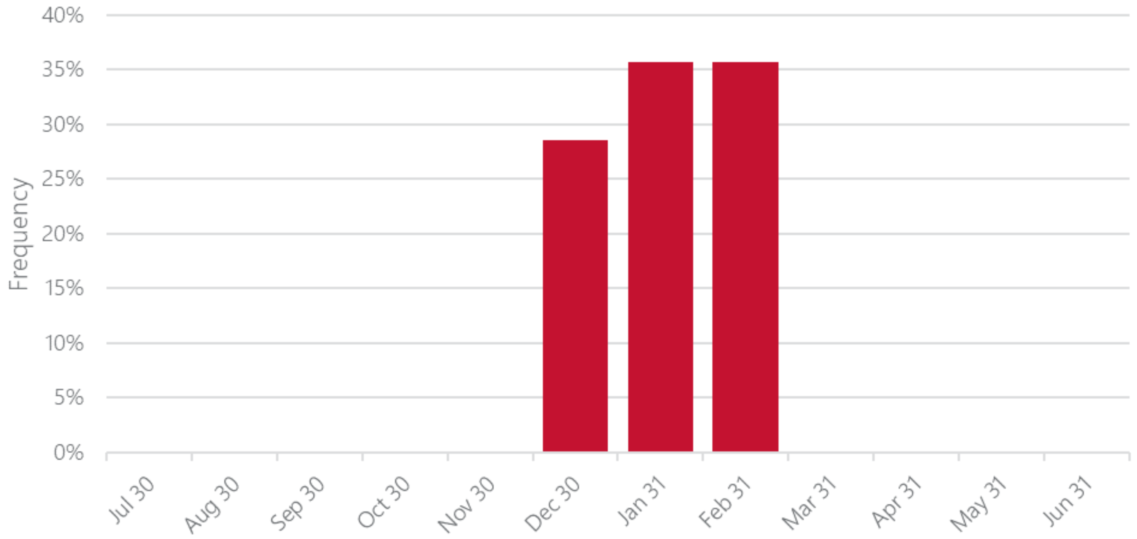


Figure 19 Projected incident frequency by season, Central scenario, 2029-30

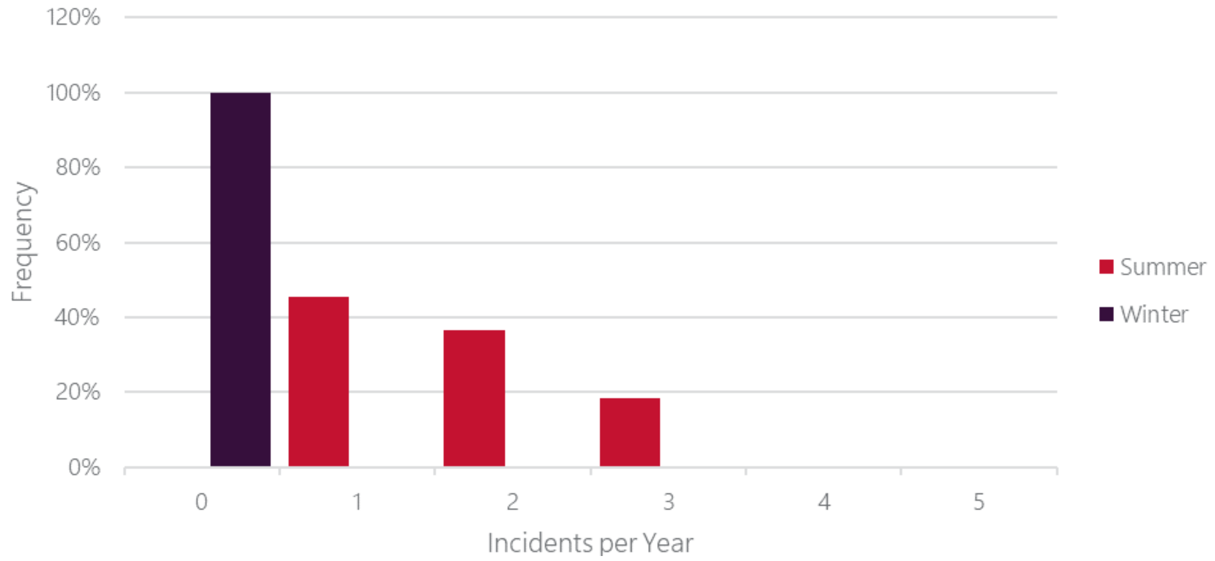
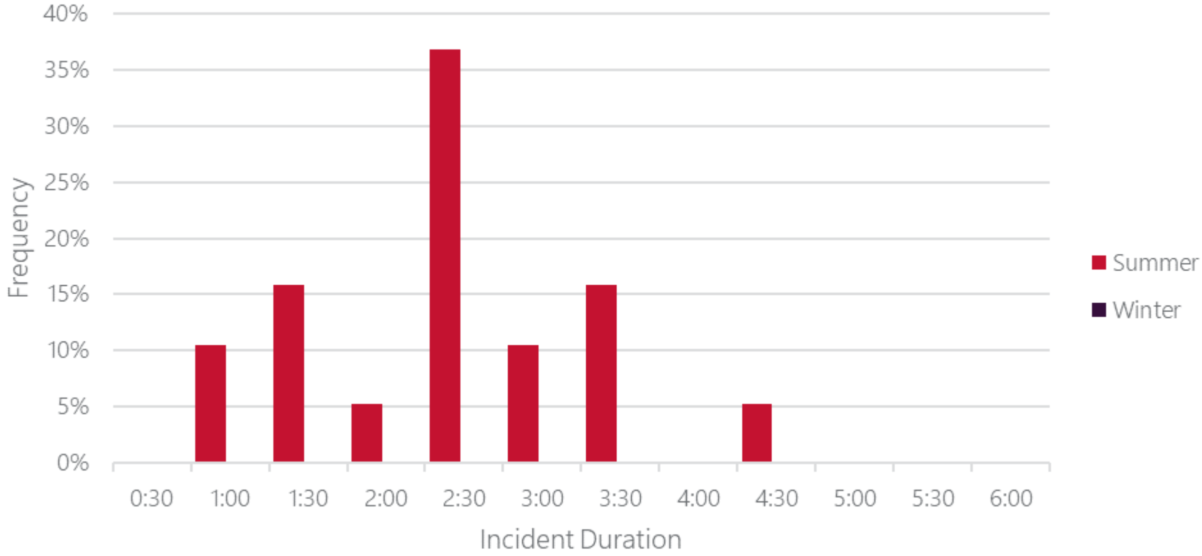


Figure 20 Projected incident duration by season, Central scenario, 2029-30



Central scenario, 2030-31

A target breach of 1,235 MW has been forecast for 2030-31 financial year in the Central scenario and is associated with a demand threshold of 13,465 MW. The following figures show the results of this breach analysis:

- Figure 21 shows the monthly distribution of the periods that exceed the demand threshold. While there are just as many incidents in winter as summer, the size of the target breach during these summer events is significantly larger.
- Figure 22 shows the projected frequency of incidents per year, with the majority of reference years indicating four events per year under 10% POE summer demand conditions, and four events per year under 10% POE winter demand conditions.
- Figure 23 shows the projected incident duration, with summer incidents up to six hours in duration, and winter incidents up to three hours in duration.

Figure 21 Projected incident frequency by forecast month, Central scenario, 2030-31

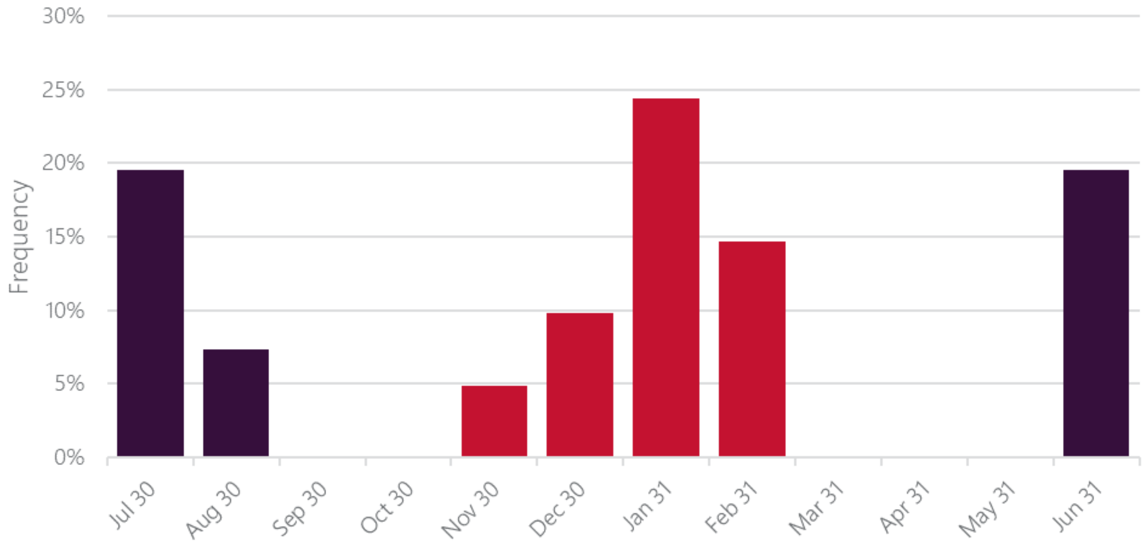


Figure 22 Projected incident frequency by season, Central scenario, 2030-31

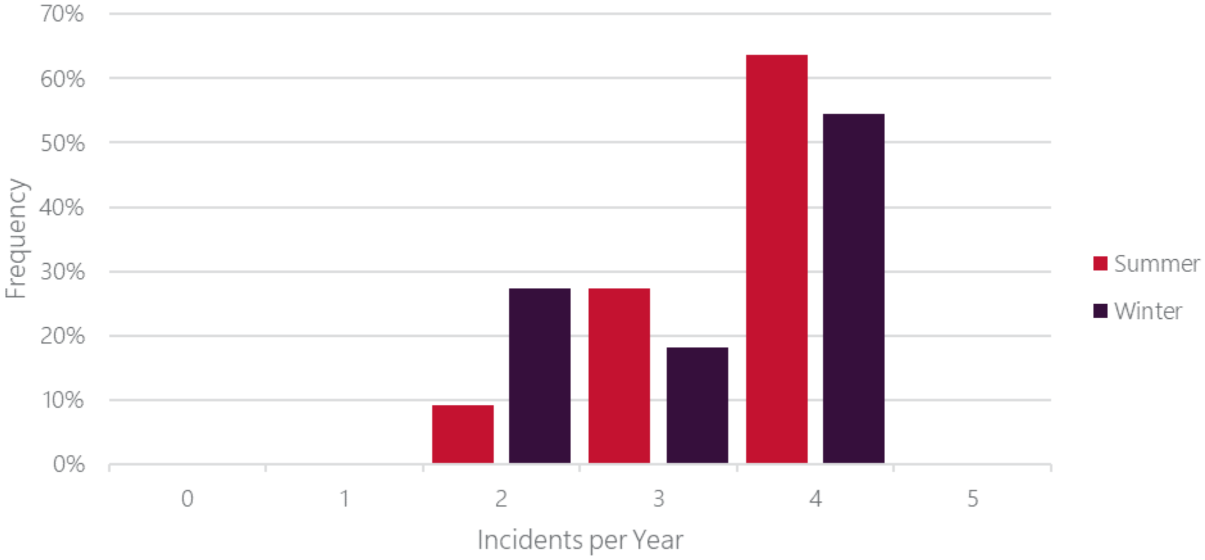
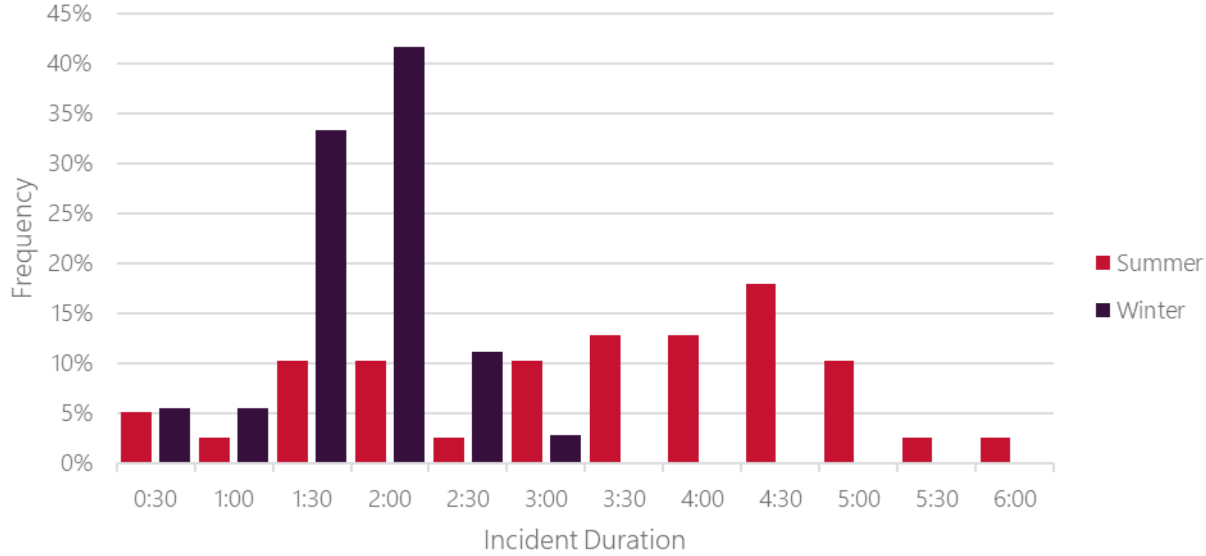


Figure 23 Projected incident duration by season, Central scenario, 2030-31



Hydrogen Superpower scenario, 2029-30

A target breach of 1,197 MW has been forecast for the 2029-30 financial year in the Hydrogen Superpower scenario and is associated with a demand threshold of 14,231 MW. The following figures show the results of this breach analysis:

- Figure 24 shows the monthly distribution of the periods that exceed the demand threshold. While there are just as many incidents in winter as summer, the size of the target breach during these summer events is significantly larger.
- Figure 25 shows the projected frequency of incidents per year, with the majority of reference years indicating three events per year under 10% POE summer demand conditions, and four events per year under 10% POE winter demand conditions.
- Figure 26 shows the projected incident duration, with summer incidents up to five hours in duration, and winter incidents up to three hours in duration.

Figure 24 Projected incident frequency by forecast month, Hydrogen Superpower scenario, 2029-30

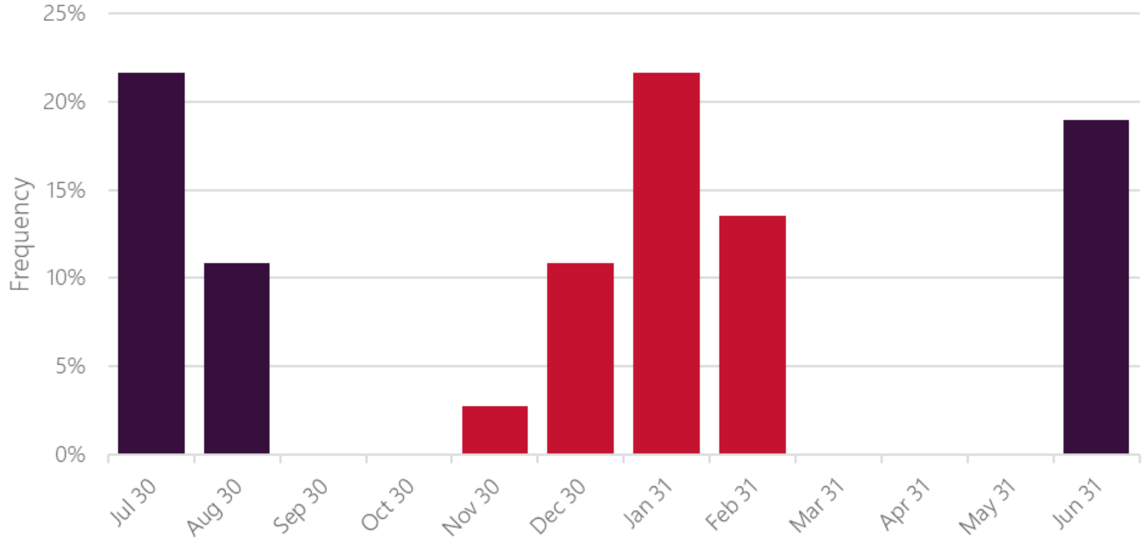


Figure 25 Projected incident frequency by season, Hydrogen Superpower scenario, 2029-30

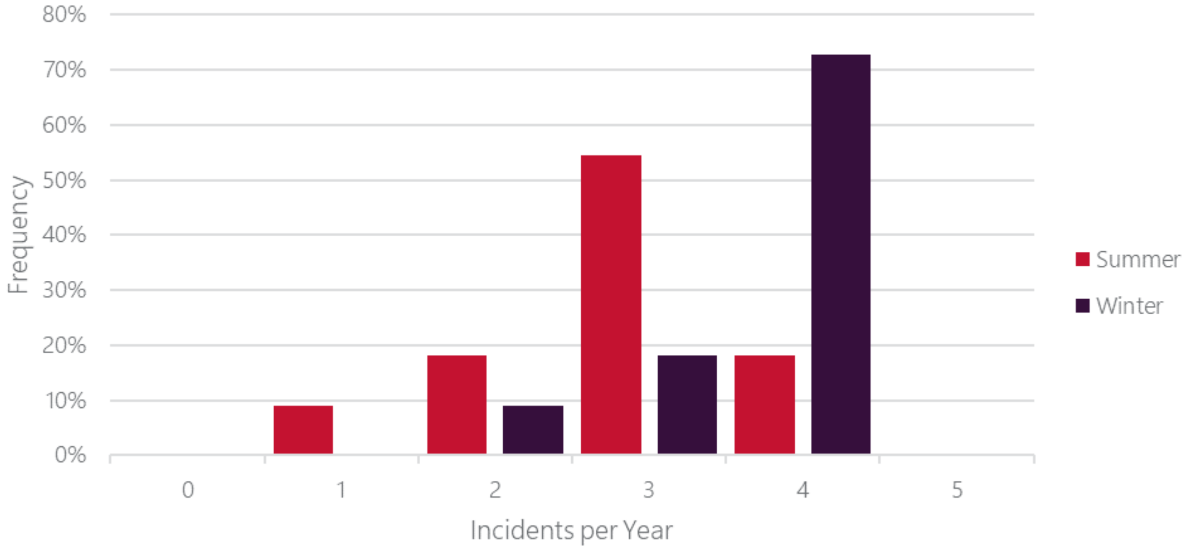
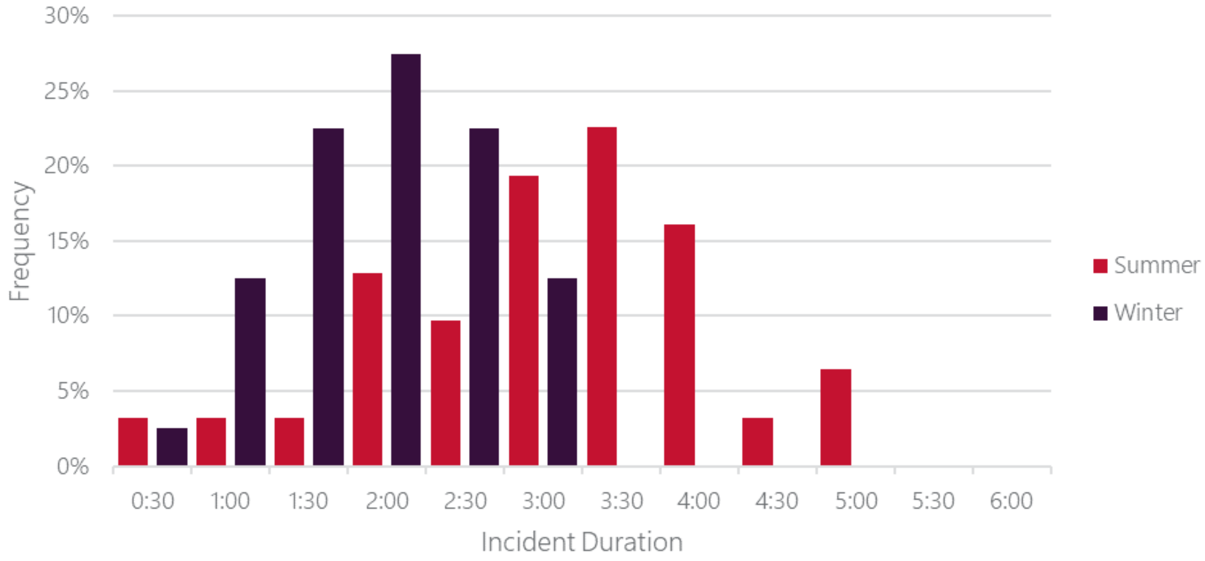


Figure 26 Projected incident duration by season, Hydrogen Superpower scenario, 2029-30



Hydrogen Superpower scenario, 2030-31

A target breach of 2,038 MW has been forecast for the 2030-31 financial year in the Hydrogen Superpower scenario and is associated with a demand threshold of 13,688 MW. The following figures show the results of this breach analysis:

- Figure 27 shows the monthly distribution of the periods that exceed the demand threshold. There are just as many incidents and similar size of the breach in winter as summer.
- Figure 28 shows the projected frequency of incidents per year, with the majority of reference years indicating four events per year under 10% POE summer demand conditions, and four events per year under 10% POE winter demand conditions.
- Figure 29 shows the projected incident duration, with summer incidents up to seven hours in duration, and winter incidents up to five hours in duration.

Figure 27 Projected incident frequency by forecast month, Hydrogen Superpower scenario with intra-regional transmission limits, 2030-31

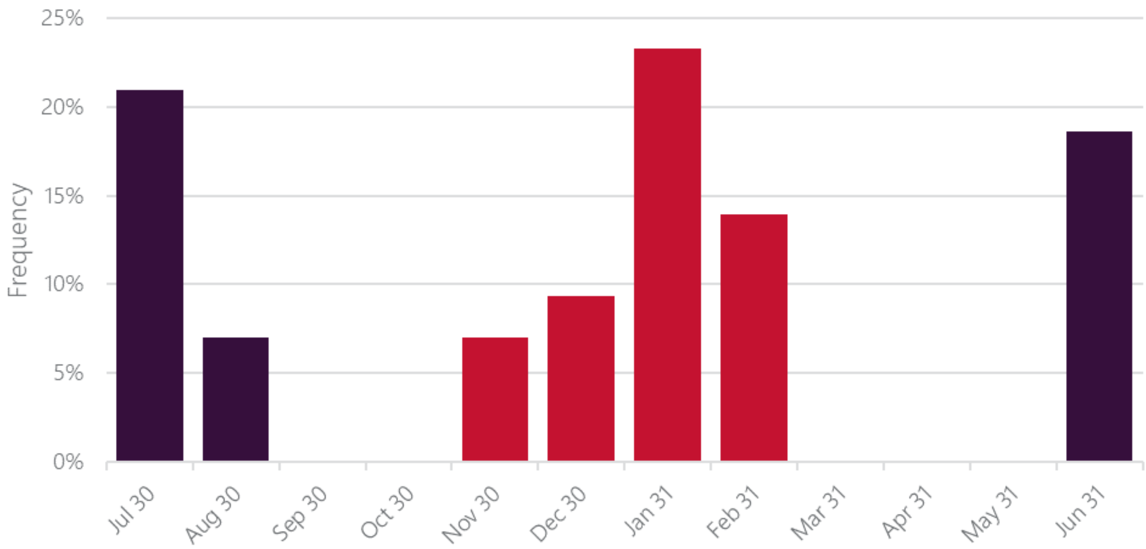


Figure 28 Projected incident frequency by season, Hydrogen Superpower scenario, 2030-31

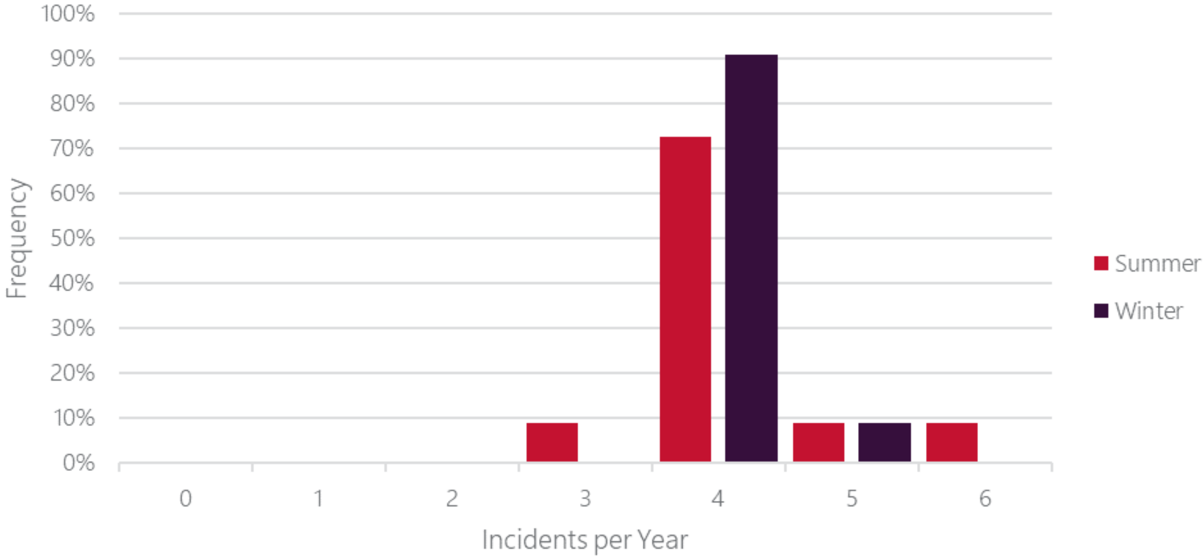
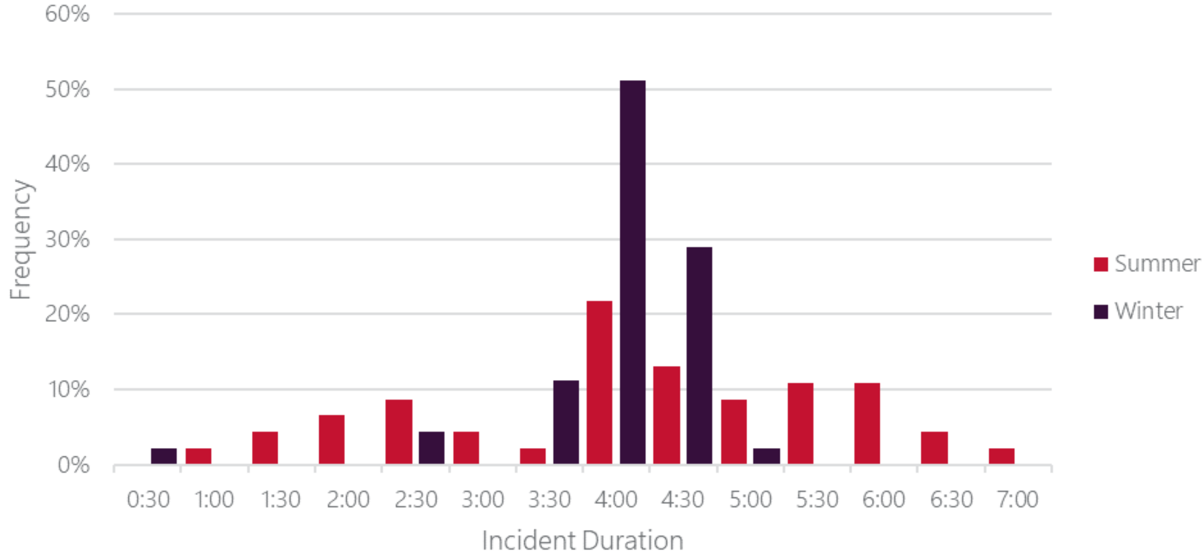


Figure 29 Projected incident duration by season, Hydrogen Superpower scenario, 2030-31



Early Coal Retirements sensitivity, 2027-28

A target breach of 129 MW has been forecast for the 2027-28 financial year in the Early Coal Retirements sensitivity and is associated with a demand threshold of 13,938 MW. The following figures show the results of this breach analysis:

- Figure 30 shows the monthly distribution of the periods that exceed the demand threshold. Due to the small size of the breach, incidents were only forecast in summer.
- Figure 31 shows the projected frequency of incidents per year, with the majority of reference years indicating one event per year under 10% POE summer demand conditions, and no events under 10% POE winter demand conditions.
- Figure 32 shows the projected incident duration, with summer incidents up to two hours in duration.

Figure 30 Projected incident frequency by forecast month, Early Coal Retirements sensitivity, 2027-28

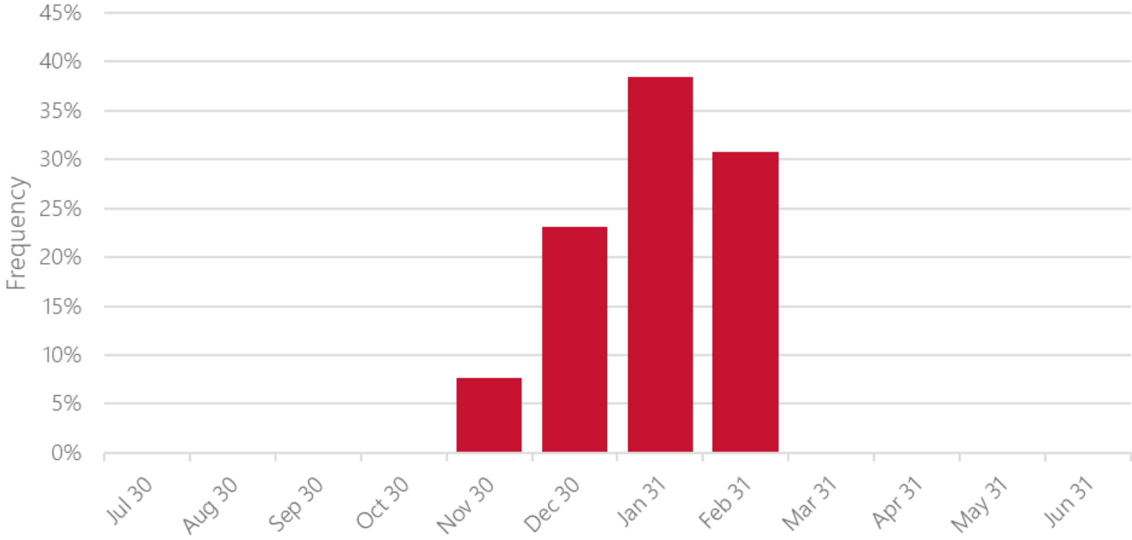


Figure 31 Projected incident frequency by season, Early Coal Retirements sensitivity, 2027-28

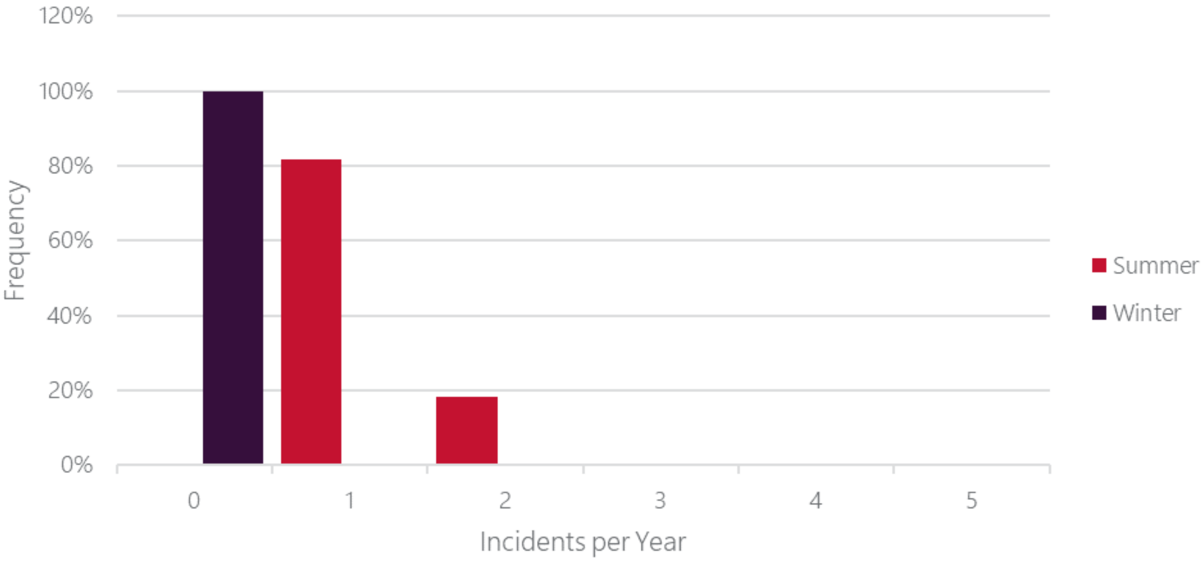
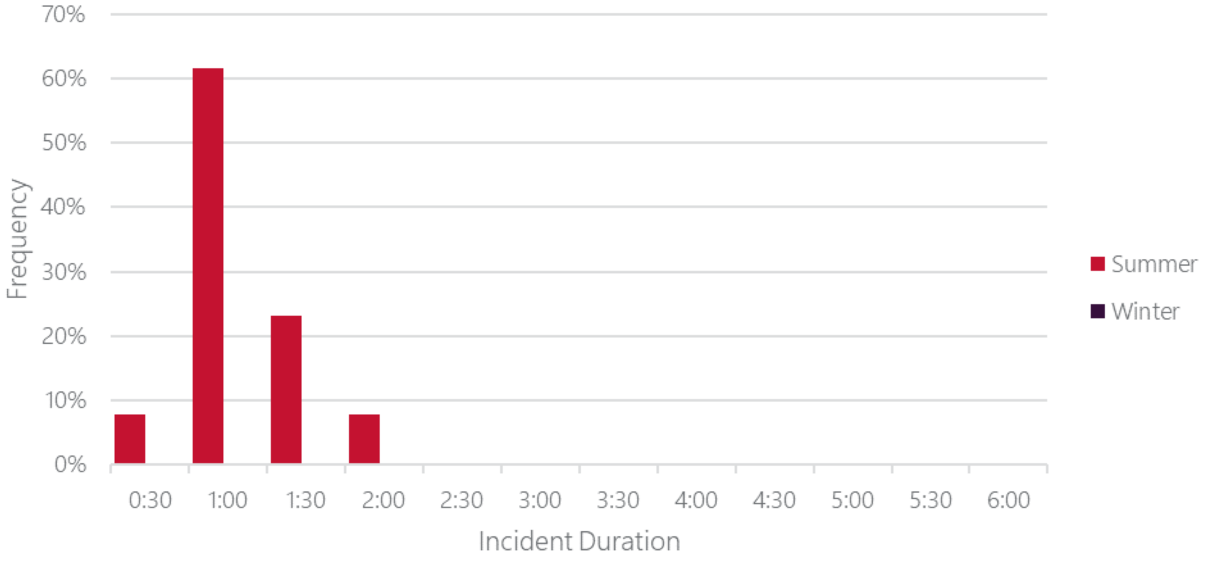


Figure 32 Projected incident duration by season, Early Coal Retirements sensitivity, 2027-28



Early Coal Retirements sensitivity, 2028-29

A target breach of 979 MW has been forecast for the 2028-29 financial year in the Early Coal Retirements sensitivity and is associated with a demand threshold of 13,396 MW. The following figures show the results of this breach analysis:

- Figure 33 shows the monthly distribution of the periods that exceed the demand threshold. There are more incidents and larger size of the breach in summer than winter.
- Figure 34 shows the projected frequency of incidents per year, with the majority of reference years indicating three events per year under 10% POE summer demand conditions, and one event per year under 10% POE winter demand conditions.
- Figure 35 shows the projected incident duration, with summer incidents up to four hours in duration, and winter incidents up to two hours in duration.

Figure 33 Projected incident frequency by forecast month, Early Coal Retirements sensitivity, 2028-29

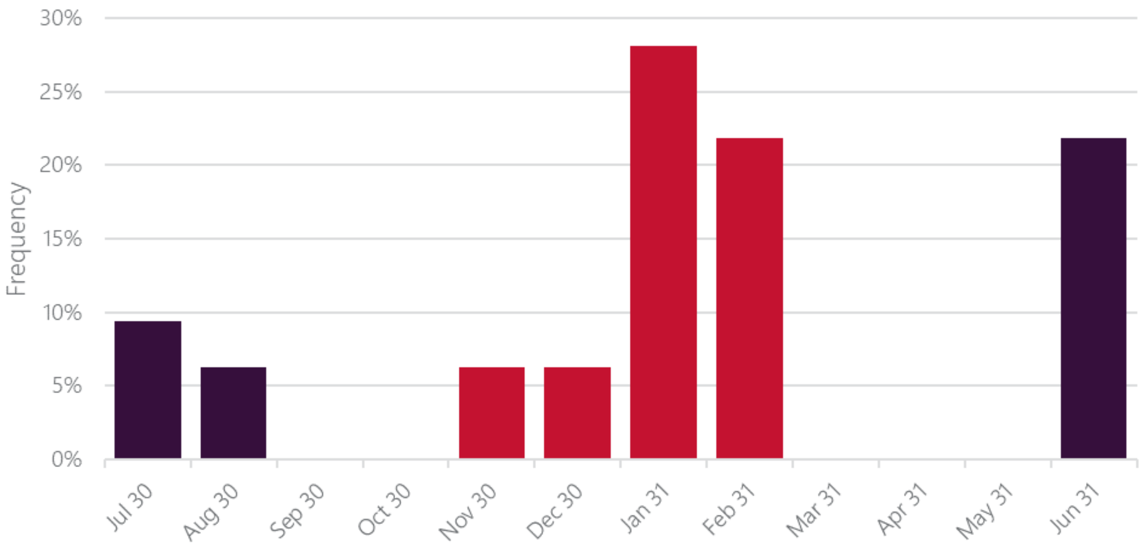


Figure 34 Projected incident frequency by season, Early Coal Retirements sensitivity, 2028-29

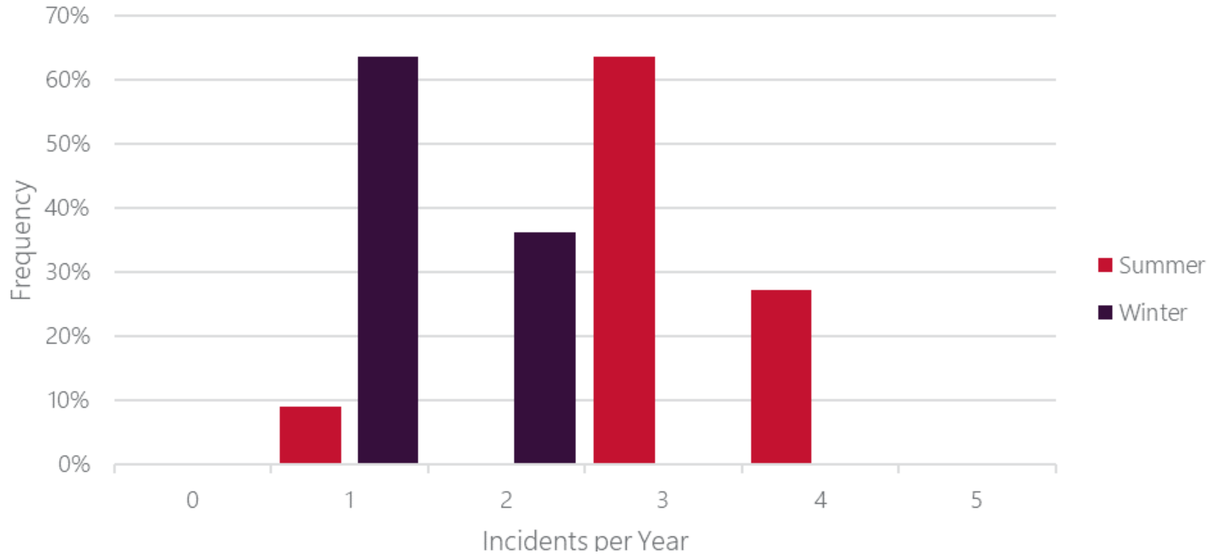
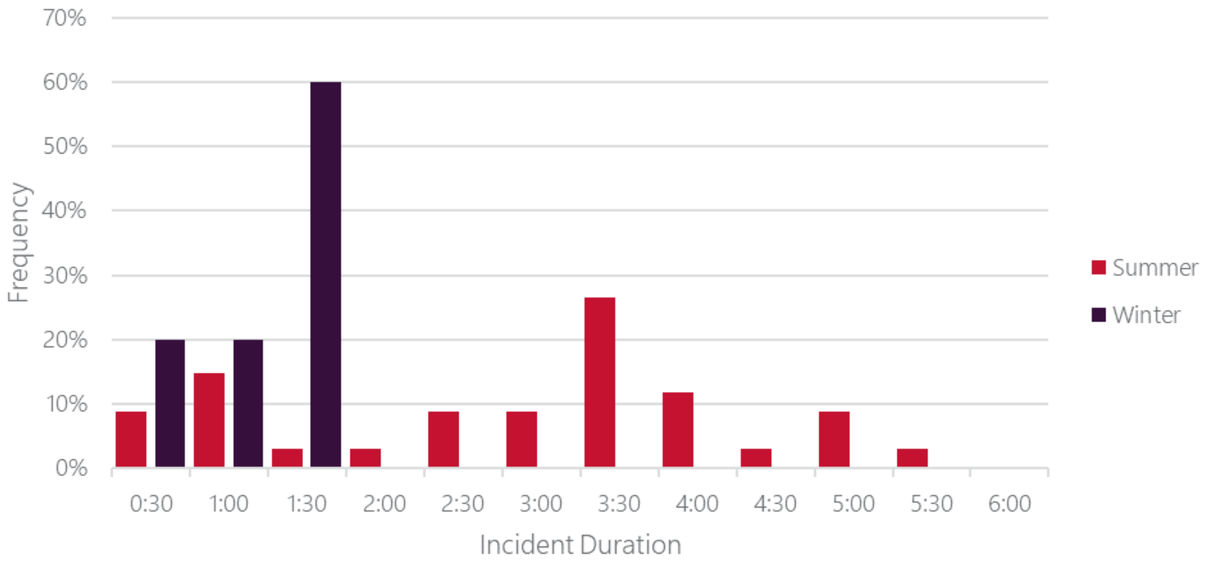


Figure 35 Projected incident duration by season, Early Coal Retirements sensitivity, 2028-29



Early Coal Retirements sensitivity, 2029-30

A target breach of 1,911 MW has been forecast for the 2029-30 financial year in the Early Coal Retirements sensitivity and is associated with a demand threshold of 12,644 MW. The following figures show the results of this breach analysis:

- Figure 36 shows the monthly distribution of the periods that exceed the demand threshold. There are just as many incidents in winter as summer and the size of the target breach during the summer events is slightly larger.
- Figure 37 shows the projected frequency of incidents per year, with the majority of reference years indicating four events per year under 10% POE summer demand conditions, and four events per year under 10% POE winter demand conditions.
- Figure 38 shows the projected incident duration, with summer incidents up to eight hours in duration, and winter incidents up to four hours in duration.

Figure 36 Projected incident frequency by forecast month, Early Coal Retirements sensitivity, 2029-30

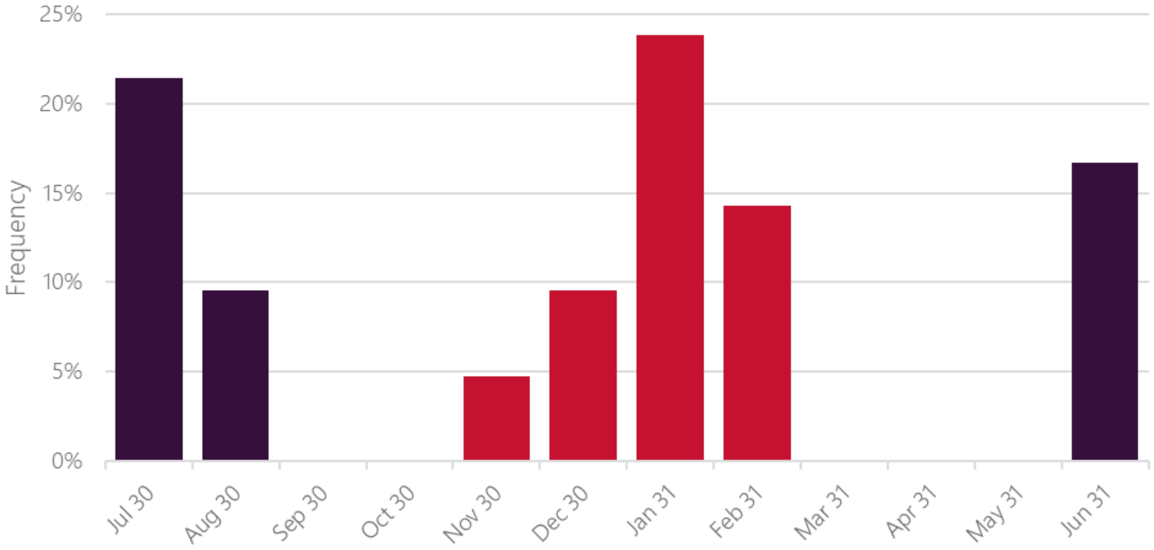


Figure 37 Projected incident frequency by season, Early Coal Retirements sensitivity, 2029-30

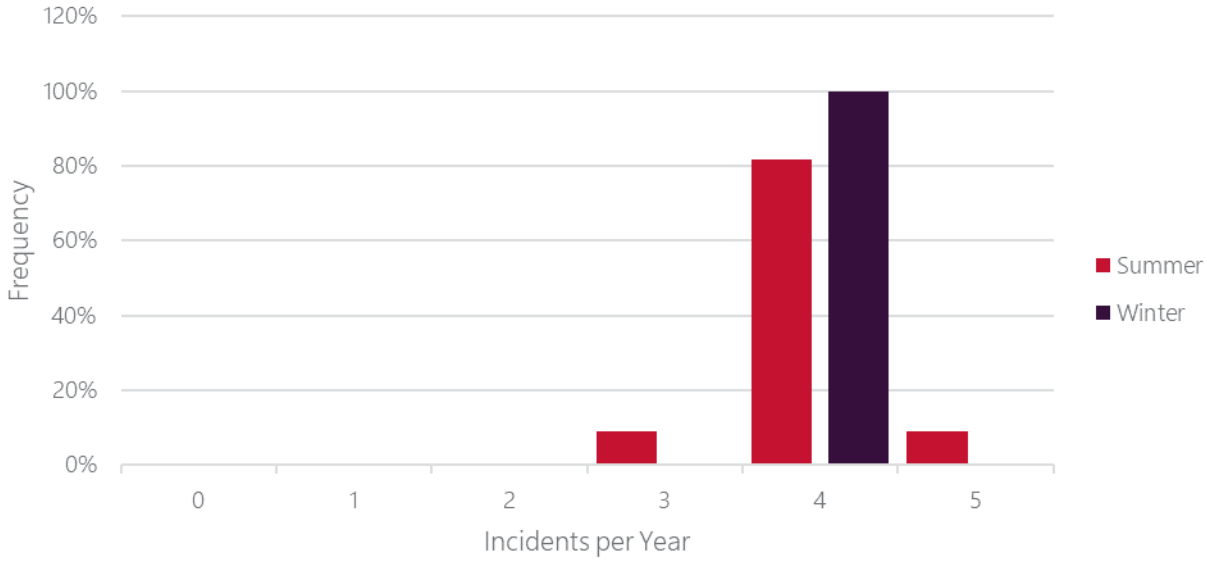
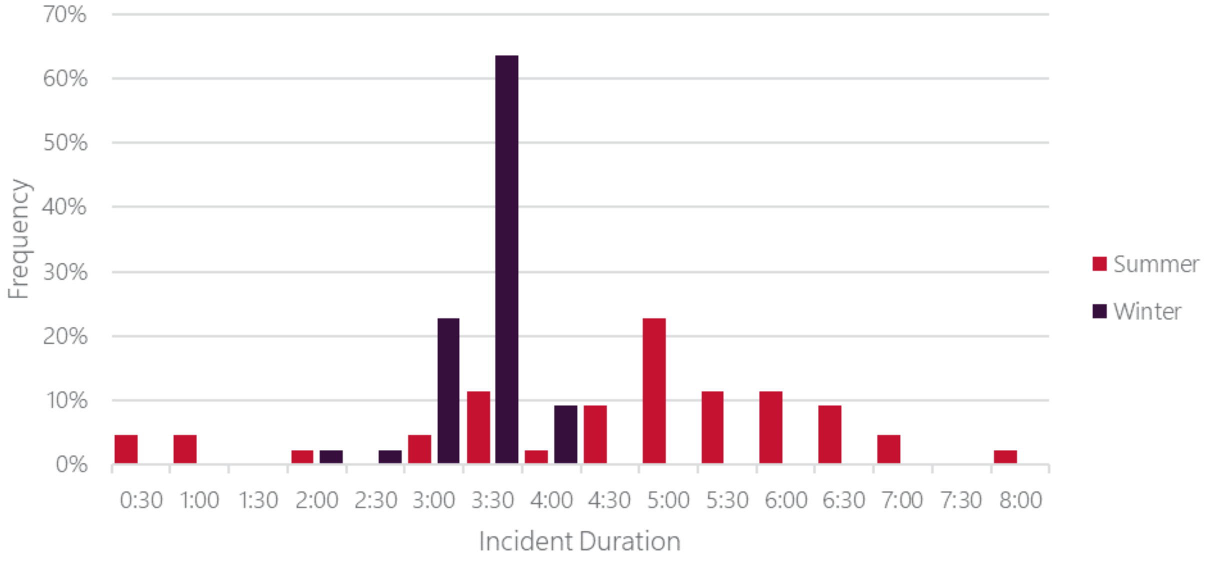


Figure 38 Projected incident duration by season, Early Coal Retirements sensitivity, 2029-30



Early Coal Retirements sensitivity, 2030-31

A target breach of 3,156 MW has been forecast for the 2030-31 financial year in the Early Coal Retirements sensitivity and is associated with a demand threshold of 11,543 MW. The following figures show the results of this breach analysis:

- Figure 39 shows the monthly distribution of the periods that exceed the demand threshold. There are just as many incidents in winter as summer and the size of the target breach during these summer events is slightly larger.
- Figure 40 shows the projected frequency of incidents per year, with the majority of reference years indicating four events per year under 10% POE summer demand conditions. However, the number of events under 10% POE winter demand conditions distribute across a wider range, with some reference years reaching 27 events per year.
- Figure 41 shows the projected incident duration. The summer incidents can reach up to 15 hours in duration, but the majority are below nine and half hours. And winter incidents can reach up to 14 hours in duration, but the majority are below six and half hours.

Figure 39 Projected incident frequency by forecast month, Early Coal Retirements sensitivity, 2030-31

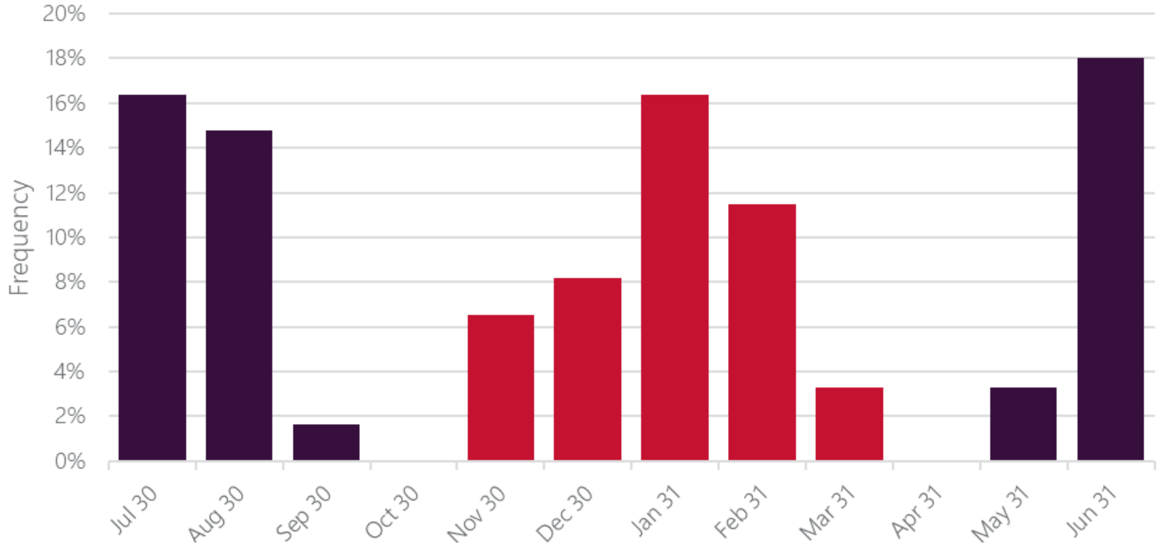


Figure 40 Projected incident frequency by season, Early Coal Retirements sensitivity, 2030-31

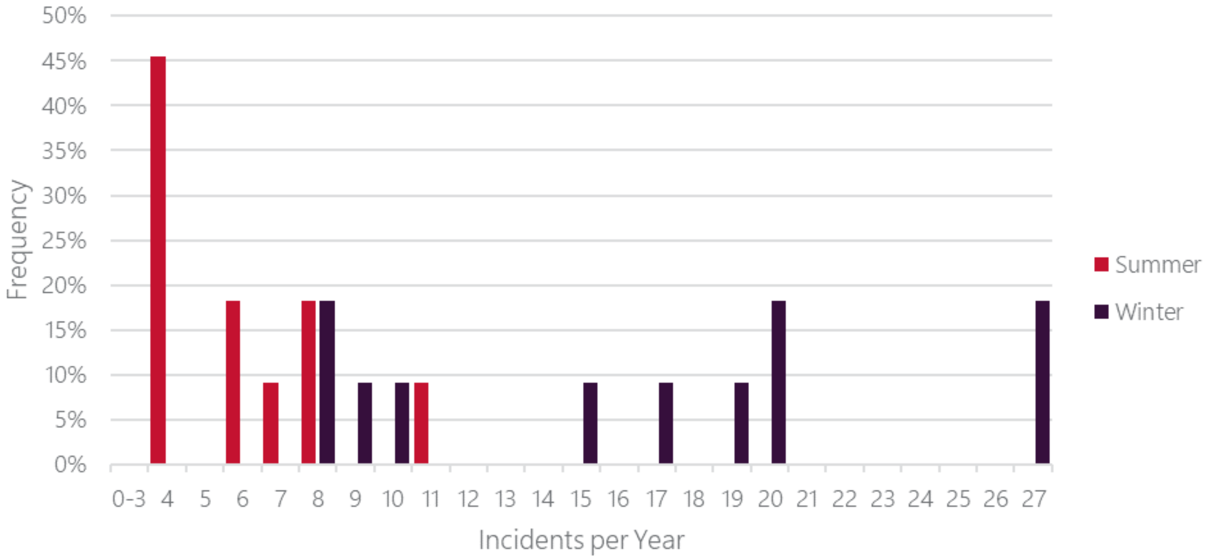
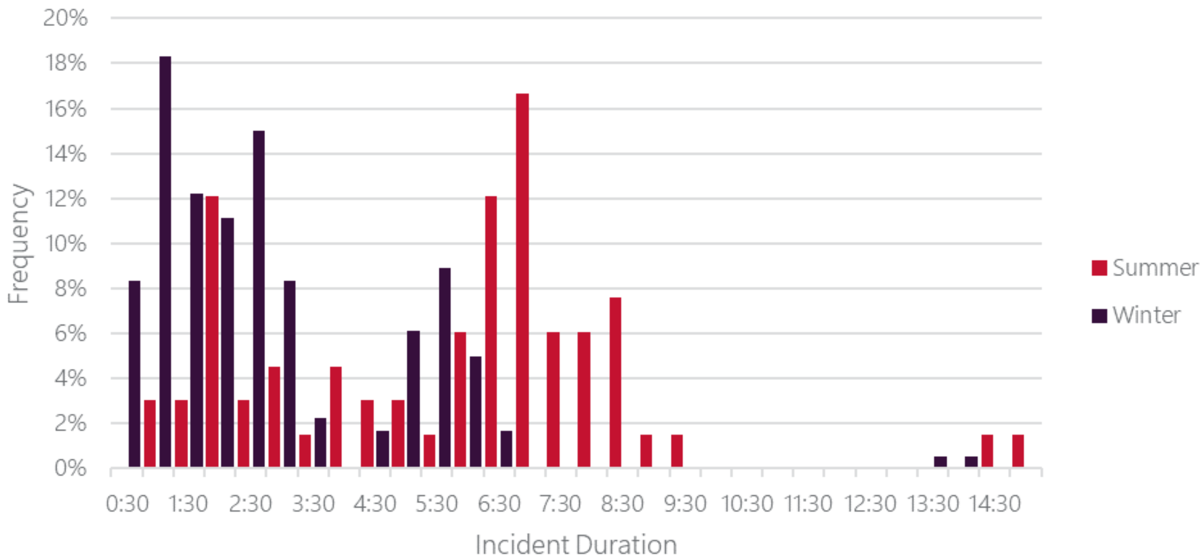


Figure 41 Projected incident duration by season, Early Coal Retirements sensitivity, 2030-31



6. Tables

Table 8 Central scenario, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,164	14,103	14,086	14,082	14,158	14,312	14,481	14,801	14,937	15,031	15,308	15,544
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,549	15,488	15,471	15,467	15,538	15,692	15,861	16,181	16,317	16,411	16,688	16,924
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,273	1,275	1,292	1,309	1,337	1,385	1,411	1,445	1,339	1,495
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	8	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	-	-	-	-	-	-	-
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	
Firm (or equivalent) capacity		16,457	16,452	17,028	17,029	17,034	17,049	17,064	17,099	15,792	15,177	14,435	13,305
Target surplus/breach		**908**	**964**	**1,556**	**1,562**	**1,496**	**1,358**	**1,204**	**918**	**-525**	**-1,235**	**-2,253**	**-3,619**

Table 9 Central scenario, with HumeLink and Sydney Ring reinforcement projects included, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,164	14,103	14,086	14,082	14,158	14,312	14,481	14,801	14,937	15,031	15,308	15,544
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,549	15,488	15,471	15,467	15,538	15,692	15,861	16,181	16,317	16,411	16,688	16,924
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,273	1,275	1,292	1,923	3,394	3,394	3,394	3,394	3,394	3,394
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	8	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	-	143	191	217	251	312	366
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity		16,457	16,452	17,028	17,029	17,034	17,663	19,264	19,299	17,992	17,377	16,802	15,570
Target surplus/breach		**908**	**964**	**1,556**	**1,562**	**1,496**	**1,972**	**3,404**	**3,118**	**1,675**	**965**	**114**	**-1,354**

Table 10 Central scenario, assessment of the EST consistent with the previous version of the EII regulations (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,164	14,103	14,086	14,082	14,158	14,312	14,481	14,801	14,937	15,031	15,308	15,544
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,549	15,488	15,471	15,467	15,538	15,692	15,861	16,181	16,317	16,411	16,688	16,924
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,396	1,396	2,062	3,394	3,394	3,394	3,394	3,394	3,394	3,394
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	34	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	230	230	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity		16,483	16,452	17,381	17,380	18,834	20,164	20,151	20,138	18,805	18,156	17,520	16,234
Target surplus/breach		**934**	**964**	**1,910**	**1,913**	**3,297**	**4,473**	**4,290**	**3,957**	**2,489**	**1,745**	**832**	**-690**

Table 11 Slow Change scenario, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,134	14,018	13,999	13,996	14,026	14,014	14,129	14,299	13,309	13,357	13,433	13,512
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,519	15,403	15,384	15,381	15,406	15,394	15,509	15,679	14,689	14,737	14,813	14,892
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,220	1,233	1,240	1,221	1,231	1,250	1,245	1,242	1,116	1,187
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	-	85	161	161	161	161	161	161	161	161	111	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	22	-	-	-	-	-	-	-	-	-	-
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	
Firm (or equivalent) capacity		16,449	16,414	16,975	16,987	16,983	16,962	16,958	16,964	15,626	14,974	14,162	12,998
Target surplus/breach		**930**	**1,011**	**1,591**	**1,606**	**1,576**	**1,568**	**1,449**	**1,285**	**938**	**238**	**-651**	**-1,895**

Table 12 Slow Change scenario, with HumeLink and Sydney Ring reinforcement projects included, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,134	14,018	13,999	13,996	14,026	14,014	14,129	14,299	13,309	13,357	13,433	13,512
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,519	15,403	15,384	15,381	15,406	15,394	15,509	15,679	14,689	14,737	14,813	14,892
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,220	1,233	1,240	1,796	3,394	3,394	3,394	3,394	3,394	3,394
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	-	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	22	-	-	-	-	37	56	51	84	111	141
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity		16,449	16,414	16,975	16,987	16,983	17,536	19,158	19,164	17,826	17,210	16,601	15,345
Target surplus/breach		930	1,011	1,591	1,606	1,576	2,142	3,649	3,485	3,138	2,473	1,789	453

Table 13 Hydrogen Superpower scenario, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,366	14,343	14,377	14,415	14,466	14,703	14,900	15,439	15,798	16,048	16,353	16,672
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,751	15,728	15,762	15,800	15,846	16,083	16,280	16,819	17,178	17,428	17,733	18,052
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,359	1,362	1,385	1,413	1,443	1,531	1,600	1,658	1,623	1,788
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	34	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	-	-	-	-	-	-	-
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	
Firm (or equivalent) capacity		16,483	16,452	17,114	17,117	17,127	17,153	17,170	17,245	15,981	15,390	14,719	13,598
Target surplus/breach		**732**	**724**	**1,352**	**1,317**	**1,281**	**1,070**	**890**	**426**	**-1,197**	**-2,038**	**-3,014**	**-4,454**

Table 14 Hydrogen Superpower scenario, with HumeLink and Sydney Ring reinforcement projects included, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,366	14,343	14,377	14,415	14,466	14,703	14,900	15,439	15,798	16,048	16,353	16,672
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,751	15,728	15,762	15,800	15,846	16,083	16,280	16,819	17,178	17,428	17,733	18,052
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,674	12,661	12,648	11,315	10,666	10,030	8,744
	New	50	80	1,359	1,362	1,385	2,060	3,394	3,394	3,394	3,394	3,394	3,394
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	34	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	-	249	337	406	464	526	594
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity		16,483	16,452	17,114	17,117	17,127	17,800	19,370	19,445	18,181	17,590	17,016	15,798
Target surplus/breach		732	724	1,352	1,317	1,281	1,717	3,090	2,626	1,003	162	-716	-2,254

Table 15 Early Coal Retirements sensitivity, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,164	14,103	14,086	14,082	14,158	14,323	14,449	14,707	14,855	14,937	15,245	15,544
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,549	15,488	15,471	15,467	15,538	15,703	15,829	16,087	16,235	16,317	16,625	16,924
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,648	11,315	10,666	10,030	8,744	8,744	8,744
	New	50	80	1,273	1,275	1,292	1,290	1,319	1,375	1,228	1,350	1,426	1,495
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	8	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	-	-	-	-	-	-	-
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	
Firm (or equivalent) capacity		16,457	16,452	17,028	17,029	17,034	17,004	15,700	15,108	14,325	13,161	13,237	13,305
Target surplus/breach		908	964	1,556	1,562	1,496	1,301	-129	-979	-1,911	-3,156	-3,388	-3,619

Table 16 Early Coal Retirements sensitivity, with HumeLink and Sydney Ring reinforcement projects included, EST assessment (MW)

Financial year ending		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Peak demand (as generated 10% POE)		14,164	14,103	14,086	14,082	14,158	14,323	14,449	14,707	14,855	14,937	15,245	15,544
Reserve margin		1,385	1,385	1,385	1,385	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Energy Security Target		15,549	15,488	15,471	15,467	15,538	15,703	15,829	16,087	16,235	16,317	16,625	16,924
Scheduled capacity	Existing	13,494	13,322	12,689	12,688	12,676	12,648	11,315	10,666	10,030	8,744	8,744	8,744
	New	50	80	1,273	1,275	1,292	3,394	3,394	3,394	3,394	3,394	3,394	3,394
Semi-Scheduled equivalent firm capacity	Existing	599	599	599	599	599	599	599	599	599	599	599	599
	New	8	85	161	161	161	161	161	161	161	161	161	161
Significant non-scheduled equivalent firm capacity	Existing	23	23	23	23	23	23	23	23	23	23	23	23
	New	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector import capacity	Existing	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975	1,975
	New	-	60	-	-	-	96	125	181	216	251	312	366
Demand side participation	Existing	308	308	308	308	308	308	308	308	308	308	308	308
	New	-	-	-	-	-	-	-	-	-	-	-	-
Firm (or equivalent) capacity		16,457	16,452	17,028	17,029	17,034	19,204	17,900	17,308	16,706	15,455	15,516	15,570
Target surplus/breach		**908**	**964**	**1,556**	**1,562**	**1,496**	**3,501**	**2,071**	**1,221**	**471**	**-862**	**-1,109**	**-1,354**