# Managing risk on Line 86 (Tamworth – Armidale)

## Market modelling report for PACR

**Transgrid**

28 July 2022

Building a better working world

# Release Notice

Ernst & Young was engaged on the instructions of NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (Transgrid) to undertake market modelling of system costs and benefits to assess various options for the "Managing risk on one of the two key 330 kV transmission lines running between Tamworth and Armidale (Line 86)" Regulatory Investment Test for Transmission (RIT-T).

The results of Ernst & Young's work are set out in this report (Report), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by Ernst & Young since the date of the Report to update it.

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# 1. Executive summary

Transgrid has engaged EY to undertake market modelling of system costs and benefits to assess various options for the "Managing risk on one of the two key 330 kV transmission lines running between Tamworth and Armidale (Line 86)" Regulatory Investment Test for Transmission (RIT-T)[1].

This Report forms a supplementary report to the Project Assessment Conclusions Report (PACR) prepared and published by Transgrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used. The Report should be read in conjunction with the PACR[1] published by Transgrid.

EY calculated the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four augmentation options for the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 Australian Energy Market Operator (AEMO) Integrated System Plan (ISP)[2,3,4]. In addition, Transgrid has requested to incorporate the most recent committed and anticipated generators from the Generation Information Page, published in June 2022[5]. As per AEMO's comments in the 2022 ISP and as advised by Transgrid, a one-year delay to the full capacity of Project EnergyConnect is assumed to become available in July 2026, following completion of inter-regional testing[4]; this is a year later than assumed in the 2022 ISP modelling.

The key differences in the assumptions between the Project Assessment Draft Report (PADR) and the PACR are as follows:

- Transgrid has requested the modelling period be reduced from 25 years to 18 years, i.e., 2023-24 to 2040-41,
- Updates from draft to final 2022 ISP assumptions to include changes in transmission network limits for some renewable energy zones (REZs) and transmission expansion costs,
- Seasonal ratings, committed and anticipated generators have been updated from the February 2022 Generation Information Page to the June 2022 Generator Information Page[5],
- Project EnergyConnect's commissioning date has been delayed by one year to July 2026,
- Gross market benefits are discounted to June 2022, as opposed to June 2021 for the PADR.

To determine the least-cost solution, EY's Time Sequential Integrated Resource Planner (TSIRP) model was used. It makes decisions for each hourly trading interval in relation to the dispatch of generators, commissioning of new entrant capacity and withdrawals of existing generation, while taking into account several operational and technical constraints. From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T[6]:

- capital costs of new generation capacity installed (capex),

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1 Transgrid, *Managing risk on Line 86 (Tamworth – Armidale)*. Available at: https://www.transgrid.com.au/projects-innovation/managing-risk-on-line-86-tamworth-armidale. Accessed 11 July 2022.

2 Note that while most of the assumptions are from the 2022 Inputs, Assumptions and Scenarios workbook published 30 June 2022, some assumptions like the timing of major upgrades are based on the final 2022 ISP outcomes.

3 AEMO, 30 June 2022, *2022 Inputs, Assumptions and Scenarios workbook*. Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed on 11 July 2022.

4 AEMO *2022 Integrated System Plan*. Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed on 11 July 2022.

5 AEMO, *NEM Generation Information June 2022*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 11 July 2022.

6 Australian Energy Regulator, 25 August 2020. *Application guidelines: Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision. Accessed 11 July 2022.

- total fixed operation and maintenance (FOM) costs of all generation capacity,
- total variable operation and maintenance (VOM) costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with REZ development.

For each simulation with an option and in the Base Case (without an option), we computed the sum of these cost components and compared the difference between each option and the Base Case. This process was completed for three scenarios, Step Change, Progressive Change and Hydrogen Superpower, as defined in the 2022 ISP[4]. The difference in present values of costs is the forecast gross market benefits[7] due to the presence of the corresponding option, as defined in the RIT-T.

The forecast gross market benefits capture the impact on transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that needs to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including Pumped Hydro Energy Storage (PHES) and large-scale battery storage between each option and the counterfactual Base Case.

Table 1 shows the details of the modelled options. Transgrid has advised EY to maintain the confidentiality of the modelled options. As such, no dollar value results are provided in this report. In addition, the y-axis in all the comparison charts throughout the Report has been removed. For more details on each option, refer to the PACR[1].

Table 1: Summary of the options[1]

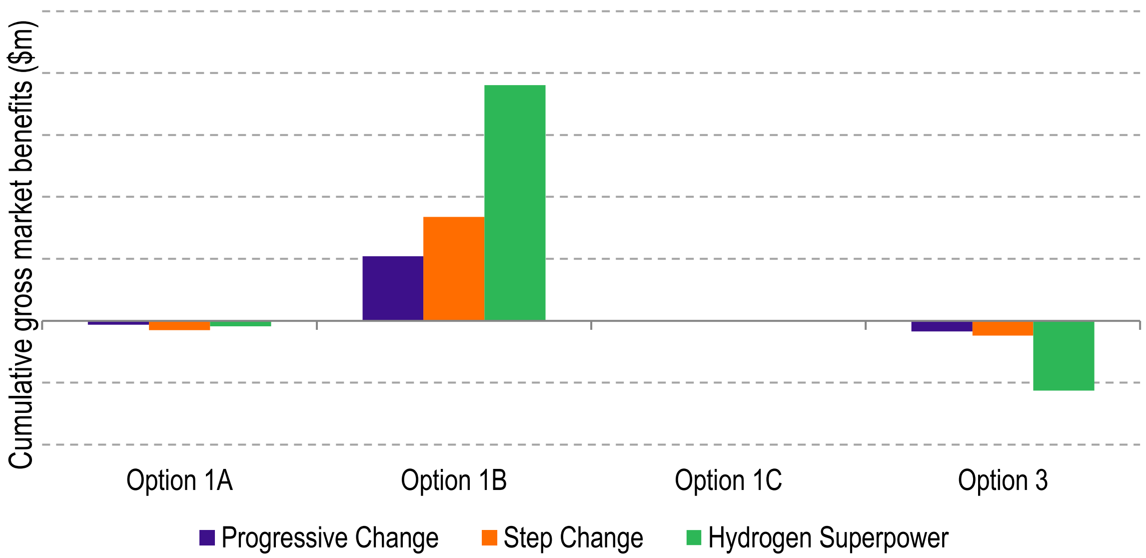
| Option | Description | Construction/commissioning date(s) |
|---|---|---|
| Option 1A | Replace Line 86 poles in-situ. | 3 month planned construction[8] from 1 March 2026 to 1 June 2026.<br>3 month planned construction from 1 August 2026 to 1 Nov 2026.<br>3 month planned construction from 1 March 2027 to 1 June 2027. |
| Option 1B | Virtual Transmission Line (VTL) from Armidale to Liddell via Tamworth for the 330 kV path.<br>Replace Line 86 poles in-situ. | VTL commissioned 1 July 2024.<br>3 month planned construction for the replacement of Line 86 from 1 March 2026 to 1 June 2026.<br>3 month planned construction from 1 August 2026 to 1 Nov 2026.<br>3 month planned construction from 1 March 2027 to 1 June 2027. |
| Option 1C | Staged replacement of Line 86 poles in-situ. | 1 month planned construction from 1 March 2028 to 1 April 2028 to replace the worst condition structures (31 of 367 poles).<br>Remaining structures (336 poles) replaced beyond the 18-year modelling period. |
| Option 3 | Rebuild Line 86 with double circuit. | 1 week of Line 86 planned outage in June 2027. |

The relative size of the forecast gross market benefits for all modelled options and scenarios is shown in Figure 1. The forecast gross market benefits of each option in each scenario need to be

[7] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the RIT-T guidelines and "net economic benefit" as defined in the RIT-T guidelines.
[8] During construction periods Line 86 is not in service. At these times, Transgrid has advised that the transfer limit for Line 85, from Armidale to Tamworth, reduces to 700 MW.

compared to the relevant avoided risk cost benefits (primarily bushfire risk) and option costs computed by Transgrid to determine the forecast net economic benefit for that option, this is not done within this Report as it was not part of our scope. The determination of forecast net economic benefit and the preferred option was conducted outside of this Report by Transgrid, by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits.

Figure 1: Composition of forecast total gross market benefits between scenarios for all options




Forecast gross market benefit outcomes are similar to the PADR in trends and relative magnitudes between scenarios and options. Sources of benefits and the key drivers are discussed below:

**Option 1A:**

- This option involves replacing Line 86 in its original position during months from March to June (2026 and 2027) and August to November (2026). Transgrid have chosen these times for pole replacements since they are expected to have a low market impact as demand (in relative terms) is typically low at these times compared to other months.
- As advised by Transgrid, it is assumed that half of the renewable capacity forecast to be installed in the New England REZ connects to the north side of Line 86, near Armidale, and the other half connects on the south side near Tamworth. As such, when flow is southward from northern New South Wales (NNS) into Central New South Wales (NCEN), lines from Armidale to Tamworth, such as Line 86, do not need to carry all of the flow.
- Since the lines between Tamworth and NCEN are south of the assumed connection points in New England, they are forecast to carry more southward flow at times of high generation in New England, compared to lines from Armidale to Tamworth. As such, constraints south of Tamworth are forecast to bind more frequently than the constraints from Armidale to Tamworth, such as Line 86.
- Therefore, the added transmission reliability for Option 1A, relative to the Base Case, is not forecast to result in material gross market benefits.

**Option 1B:**

- Transgrid has advised that Option 1B assumes the same replacement schedule as Option 1A, along with the installation of two batteries to provide VTL services that increase the N-1 thermal limits by 200 MW for the 330 kV path between Armidale and Liddell via Tamworth.

- As discussed for Option 1A, the southward flow limit from NNS to NCEN is typically forecast to be set by limits between Tamworth and NCEN. Increasing the N-1 thermal limit of the 330 kV lines from Tamworth to Liddell, by locating one of the VTL batteries close to Tamworth, is forecast to allow more NCEN demand to be met by generation from New England or Queensland. This results in positive gross market benefits.

**Option 1C:**

- This option is similar to Option 1A; however, the replacement of Line 86 occurs in stages. As with Option 1A, Option 1C is not forecast to result in material gross market benefits.

**Option 3:**

- Option 3 assumes Line 86 is rebuilt as a double circuit 330 kV option. It was found that doing so is not typically forecast to increase the southerly transfer limit between NNS and NCEN, since the limit is generally caused by constraints further south of Line 86.
- The double circuit augmentation is forecast to reduce the impedance along the 330 kV flow path from Armidale to Liddell, via Tamworth. This increases the proportion of flow across the 330 kV path, as opposed to the assumed 500 kV route created by the New England REZ augmentation.
- Consequently, more flow is diverted towards the 330 kV lines from Tamworth to Liddell, compared to the Base Case. This is expected to cause the 330 kV limits south of Line 86 to restrict flow from NNS to NCEN, even though the 500 kV flow path may still have headroom. As such the option is forecast to have negative gross market benefits.

# 2. Introduction

Transgrid has engaged EY to undertake market modelling of system costs and benefits to assess various options for the "Managing risk on one of the two key 330 kV transmission lines running between Tamworth and Armidale (Line 86)" Regulatory Investment Test for Transmission (RIT-T)[1]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in regulated electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Conclusion Report (PACR) published by Transgrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used. The Report should be read in conjunction with the PACR[1] published by Transgrid.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four options using input assumptions generally derived from the 2022 Integrated System Plan's (ISP)[2]. In addition, Transgrid has requested to incorporate the most recent committed and anticipated generators from the Generation Information Page, published in June 2022[5]. Furthermore, as per AEMO's comments in the 2022 ISP and as advised by Transgrid, the full capacity of Project EnergyConnect is assumed to become available in July 2026, following completion of inter-regional testing[4]; this is a year later than assumed in the 2022 ISP modelling.

The options were defined by Transgrid and are described in detail in the PACR, therefore, readers are advised to read this report in conjunction with PACR to get the required context and details. A modelling period of 18 years from 2023-24 to 2040-41 is considered, as requested by Transgrid. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator (AER)[6].

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

Each category of gross market benefits is computed annually (based on hourly time series modelling) across an 18-year modelling period from 2023-24 to 2040-41. Benefits presented are discounted to June 2022 using a 5.5% real, pre-tax discount rate as selected by Transgrid. This value is consistent with the value applied by the AEMO in the 2022 ISP[3].

This modelling considers four options as listed in the table below. For more details on each option, refer to the Transgrid PACR[1].

Table 2: Summary of the Options[1]

| Option | Description | Construction/commissioning date(s) |
|---|---|---|
| Option 1A | Replace Line 86 poles in-situ. | 3 month planned construction[9] from 1 March 2026 to 1 June 2026.<br>3 month planned construction from 1 August 2026 to 1 Nov 2026.<br>3 month planned construction from 1 March 2027 to 1 June 2027. |
| Option 1B | VTL from Armidale to Tamworth to Liddell for the 330 kV path.<br>Replace Line 86 poles in-situ. | VTL commissioned 1 July 2024.<br>3 month planned construction for the replacement of Line 86 from 1 March 2026 to 1 June 2026.<br>3 month planned construction from 1 August 2026 to 1 Nov 2026.<br>3 month planned construction from 1 March 2027 to 1 June 2027. |
| Option 1C | Replacement of Line 86 poles in-situ. | 1 month planned construction from 1 March 2028 to 1 April 2028 to replace the worst condition structures (31 of 367 poles).<br>Remaining structures (336 poles) replaced beyond the 18-year modelling period. |
| Option 3 | Rebuild Line 86 with double circuit. | 1 week of Line 86 planned outage in June 2027. |

The forecast gross market benefits of each option need to be compared to the relevant avoided risk cost benefits (primarily bushfire risk) and option costs computed by Transgrid to determine the forecast net economic benefit for that option, this is not done within this Report as it was not part of our scope. The determination of forecast net economic benefit and the preferred option was conducted outside of this Report by Transgrid, by incorporating the forecast gross market benefits into the calculation of net economic benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[6].

The Report is structured as follows:

- Section 3 describes assumptions and scenario inputs modelled in this study.
- Section 4 presents the NEM capacity and generation outlook without the augmentation options.
- Section 5 presents the forecast gross market benefits for each option. It is focussed on identifying and explaining the key sources of forecast gross market benefits of all options.
- Appendix A provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Appendix B outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Appendix C provides an overview of model inputs and methodologies related to supply of energy.
- Appendix D provides the ratings used in the model.
- Appendix E describes constraint equations formulation.

[9] During construction periods Line 86 is not in service. At these times, Transgrid has advised that the transfer limit for Line 85, from Armidale to Tamworth, reduces to 700 MW.

# 3. Scenario assumptions

## 3.1 Key assumptions for modelled scenarios

The options proposed by Transgrid have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from AEMO's 2022 ISP[3]. These scenarios are summarised in Table 3.

Table 3: Overview of key input parameters in the Step Change, Progressive Change and Hydrogen Superpower scenarios[3,4]

| Key drivers input parameter | Scenario | | |
|---|---|---|---|
| | Progressive Change | Step Change | Hydrogen Superpower |
| Underlying consumption | ESOO 2021 (ISP 2022)[10] - Progressive Change | ESOO 2021 (ISP 2022)[10] - Step Change | ESOO 2021 (ISP 2022)[10] - Hydrogen Superpower |
| Committed and anticipated generation | Latest committed and anticipated generators from the Generation Information Page, published in June 2022[5] | | |
| New entrant capital cost for wind, solar SAT, OCGT, CCGT, PHES, and large-scale batteries[11] | AEMO Inputs, Assumptions and Scenarios workbook - Progressive Change | AEMO Inputs, Assumptions and Scenarios workbook - Step Change | AEMO Inputs, Assumptions and Scenarios workbook - Hydrogen Superpower |
| Retirements of coal-fired power stations | AEMO Inputs, Assumptions and Scenarios workbook - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030. Includes recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[12] | AEMO Inputs, Assumptions and Scenarios workbook - Step Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Includes recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[12] | AEMO Inputs, Assumptions and Scenarios workbook - Hydrogen Superpower: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Includes recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[12] |
| Gas fuel cost | AEMO Inputs, Assumptions and Scenarios workbook - Progressive Change: Lewis Grey Advisory 2020, Central | AEMO Inputs, Assumptions and Scenarios workbook: Lewis Grey Advisory 2020, Step Change | |
| Coal fuel cost | AEMO Inputs, Assumptions and Scenarios workbook - Progressive Change: Wood Mackenzie, Central | AEMO Inputs, Assumptions and Scenarios workbook: Wood Mackenzie, Step Change | |
| NEM carbon budget | AEMO Inputs, Assumptions and Scenarios workbook - Progressive Change: 932 Mt $CO_2$-e 2030-31 to 2050-51 | AEMO Inputs, Assumptions and Scenarios workbook - Step Change: 891 Mt $CO_2$-e 2023-24 to 2050-51 | AEMO Inputs, Assumptions and Scenarios workbook - Hydrogen Superpower: 453 Mt $CO_2$-e 2023-24 to 2050-51 |

[10] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed on 11 July 2022.

[11] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle gas Turbine

[12] AEMO, *Generating unit expected closure year June 2022*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 11 July 2022

| Key drivers input parameter | Scenario | | |
|---|---|---|---|
| | Progressive Change | Step Change | Hydrogen Superpower |
| Victoria Renewable Energy Target (VRET) | 40% renewable energy by 2025 and 50% renewable energy by 2030<br>VRET 2 including 600 MW of renewable capacity by 2025 | | |
| Queensland Renewable Energy Target (QRET) | 50% by 2030 | | |
| Tasmanian Renewable Energy Target (TRET) | AEMO Inputs, Assumptions and Scenarios workbook: 200% Renewable generation by 2040 | | |
| New South Wales (NSW) Electricity Infrastructure Roadmap | AEMO Inputs, Assumptions and Scenarios workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per the 2022 ISP, 2 GW of long duration storage (8 hrs or more) by 2029-30 | | |
| EnergyConnect | 2022 Integrated System Plan comment: EnergyConnect commissioned by July 2026 | | |
| Western Victoria Transmission Network Project | 2022 Integrated System Plan: Western Victoria upgrade commissioned by July 2026 | | |
| HumeLink | 2022 Integrated System Plan – Progressive Change: HumeLink commissioned by July 2035 | 2022 Integrated System Plan – Step Change: HumeLink commissioned by July 2028 | 2022 Integrated System Plan – Hydrogen Superpower: HumeLink commissioned by July 2027 |
| Marinus Link | 2022 Integrated System Plan:1$^{st}$ cable commissioned by July 2029 and 2$^{nd}$ cable by July 2031 | | |
| Victoria to NSW Interconnector (VNI) Upgrade (VNI Minor) | 2022 Integrated System Plan: VNI Minor commissioned by December 2022 | | |
| NSW to Queensland Interconnector (QNI) Upgrade (QNI Minor) | 2022 Integrated System Plan: QNI minor commissioned by mid-2023 | | |
| QNI Connect | 2022 Integrated System Plan – Progressive Change: QNI Connect commissioned by July 2036 | 2022 Integrated System Plan – Step Change: QNI Connect commissioned by July 2032 | 2022 Integrated System Plan – Hydrogen Superpower: QNI Connect commissioned by July 2029 |
| QNI Connect 2 | 2022 Integrated System Plan: Not commissioned | | 2022 Integrated System Plan: QNI Connect stage 2 commissioned by July 2030 |
| VNI West | 2022 Integrated System Plan – Progressive Change: VNI West commissioned by July 2038 | 2022 Integrated System Plan – Step Change: VNI West commissioned by July 2031 | 2022 Integrated System Plan – Hydrogen Superpower: VNI West commissioned by July 2030 |
| Victorian SIPS | 2022 Integrated System Plan: 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.<br>After SIPS contract ends (March 2032) 300 MW can be deployed in the market by the operator on a commercial basis. | | |
| New-England REZ Transmission | 2022 Integrated System Plan – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038 | 2022 Integrated System Plan – Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035 | 2022 Integrated System Plan – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, and New England REZ Extension commissioned by July 2031 |

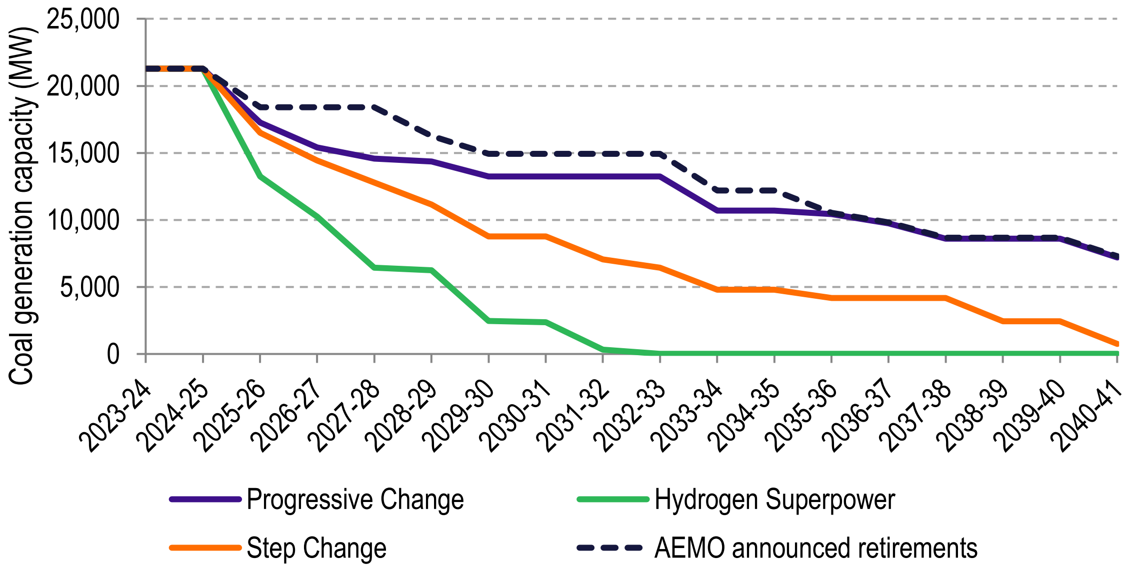
| Key drivers input parameter | Scenario | | |
|---|---|---|---|
| | Progressive Change | Step Change | Hydrogen Superpower |
| New generic renewable and storage capacity connection point assumptions for the New-England REZ | As advised by Transgrid, before the New England REZ augmentation stage 1, half of the capacity connects to the existing 330 kV Tamworth substation and the other half connects to the existing 330 kV Armidale substation. After the New England REZ augmentation, half of the capacity connects to the new 500 kV Tamworth East substation and the other half connects to the new 500 kV Armidale South substation | | |
| Snowy 2.0 | AEMO Inputs, Assumptions and Scenarios workbook: Snowy 2.0 is commissioned by December 2026 | | |

# 4. NEM outlook without options

Before presenting the forecast benefits of the options, it is useful to understand in the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the Base Case.

According to the scenario settings selected by Transgrid and in line with the 2022 ISP, thermal retirements in the model are on a least-cost basis. Coal retirement dates are at or earlier than their end-of-technical life or announced retirement year. Forecast coal capacity in the Base Case as an output of the modelling is illustrated in Figure 2.

Figure 2: Forecast coal capacity in the NEM by year in the Base Case




The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, legislated renewable energy targets (NSW Electricity Infrastructure Roadmap, VRET, TRET and QRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. The model forecasts the entire coal capacity to retire by the early 2030s in the Hydrogen Superpower scenario, while this is around 2040 for the Step Change scenario and in the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the modelling period.

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 3 and the corresponding generation mix in Figure 4. In the Base Case, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas.

Figure 3: NEM capacity mix forecast for the Step Change scenario in the Base Case

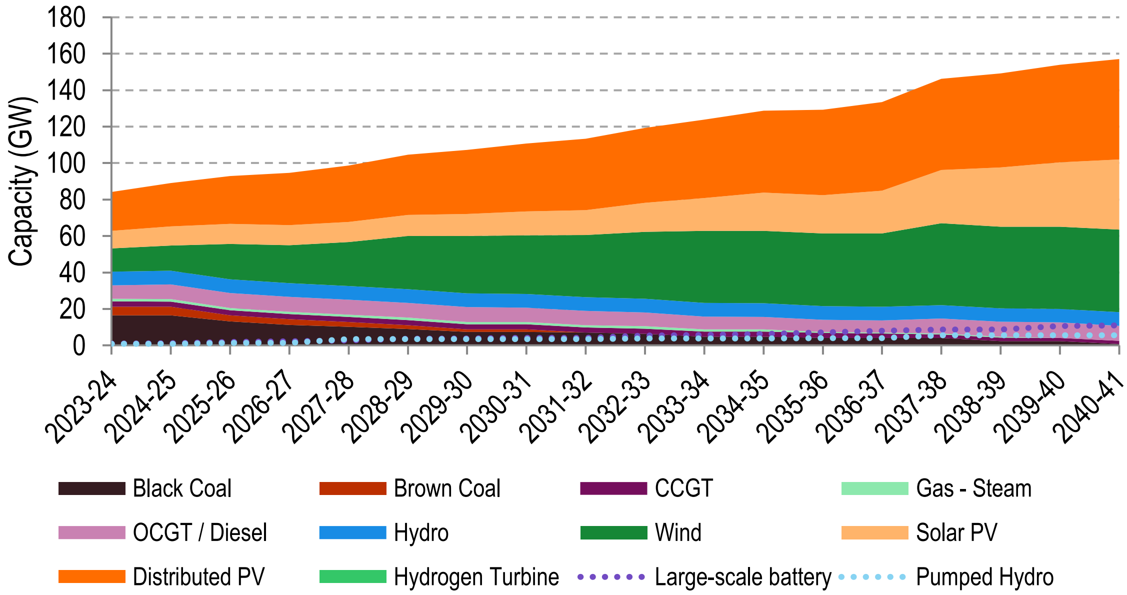
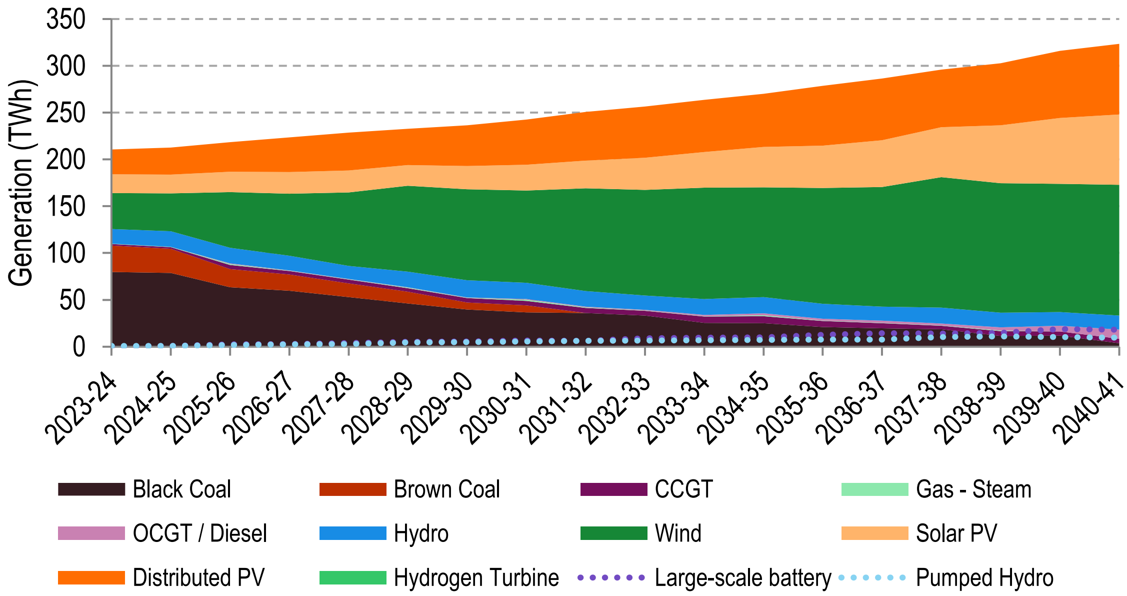



Figure 4: NEM generation mix forecast for the Step Change scenario in the Base Case




Up to 2030, new wind and solar build is forecast to be largely driven by the assumed state-based renewable energy targets and the assumed carbon budget constraint. The forecast increase in renewable capacity leads to some economically driven coal generation retirements in Queensland and NSW. To replace the retiring capacity, large-scale battery storage capacity is forecast to begin increasing from the late 2020s, then PHES and wind capacity is forecast to increase from the mid-2030s. Solar PV. OCGT capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast gas-fired capacity also supports reserve requirements during peak demand times. Overall, the NEM is forecast to have around 160 GW total capacity by 2040-41 (note that total capacity includes distributed PV, which is an input assumption, and also PHES and large-scale battery capacity, which is not in the stacked chart). The forecast timing of entry of most new installed capacity coincides with coal-fired generation retirements.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 5 and Figure 7 show the differences in the NEM capacity development of other scenarios relative to the Step Change scenario, while Figure 6 and Figure 8 show generation differences. The differences are presented as the alternative scenario minus the Step Change scenario, and both capacity and generation differences for each scenario show similar trends. As the figures show, the Progressive Change scenario retains higher coal generation and less wind and solar generation compared to the Step Change scenario due to different assumptions such as the carbon budget, demand forecast and other underlying input data. The Hydrogen Superpower scenario has higher wind and solar capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario, along with a more restrictive carbon budget.

Figure 5: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case

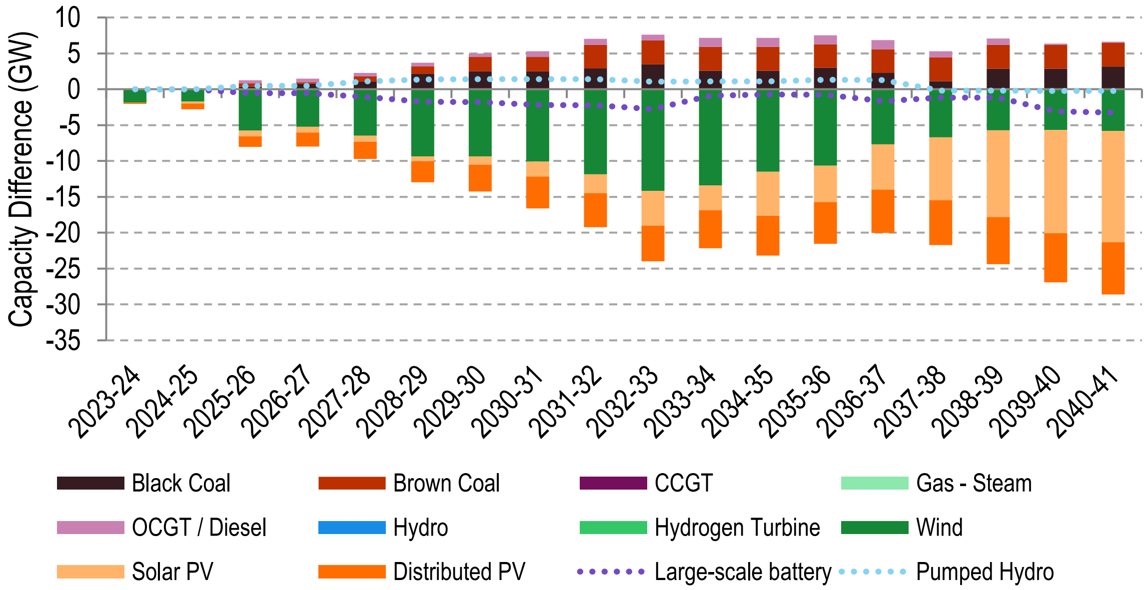



Figure 6: Difference in NEM generation forecast between the Progressive Change and Step Change scenarios in the Base case

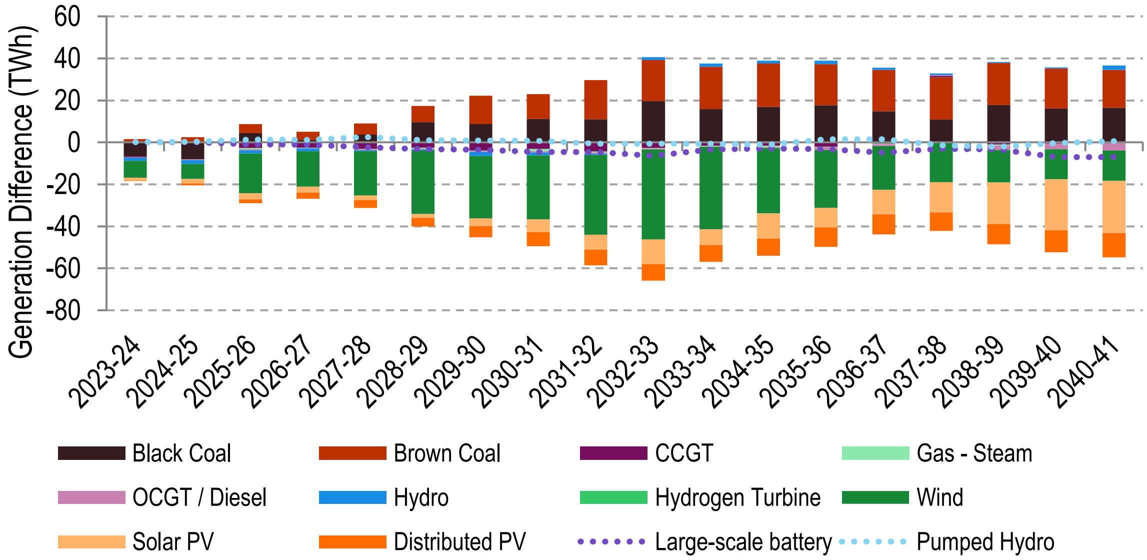


Figure 7: Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case

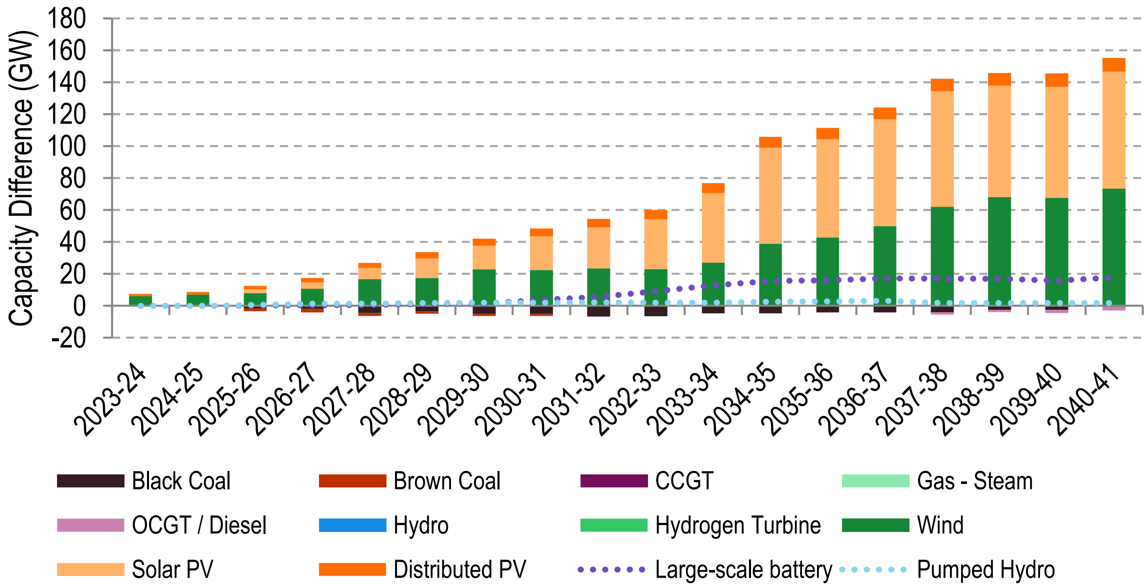
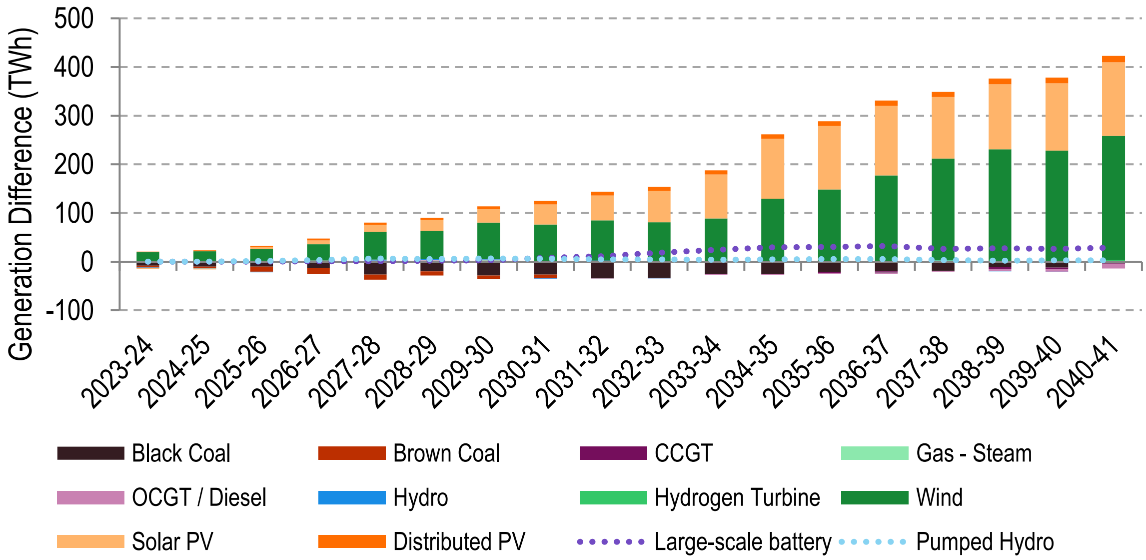



Figure 8: Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case

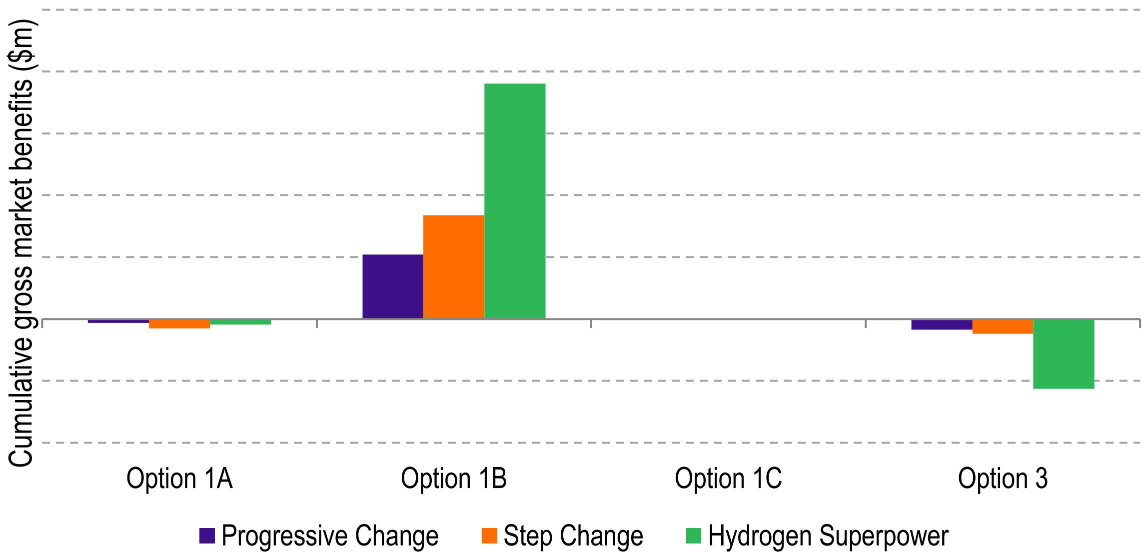


# 5. Forecast gross market benefit outcomes

## 5.1 Market modelling outcomes overview

Figure 9 shows the relative size of forecast gross market benefits over the modelled 18-year horizon for all options across all scenarios. Throughout this section the y-axis in all the comparison charts is removed to maintain the confidentiality of the modelled options as requested by Transgrid.

Figure 9: Composition of forecast total gross market benefits between scenarios for all options




Transgrid informed us that they have concluded that Option 1C is the preferred option based on the forecast net benefits (after incorporating forecast gross market benefits, avoided risk cost benefits (primarily bushfire risk) and assumed development costs of the options). The rest of Section 5 explores the forecast sources of these benefits, with a focus on the preferred option as determined by Transgrid: Option 1C.

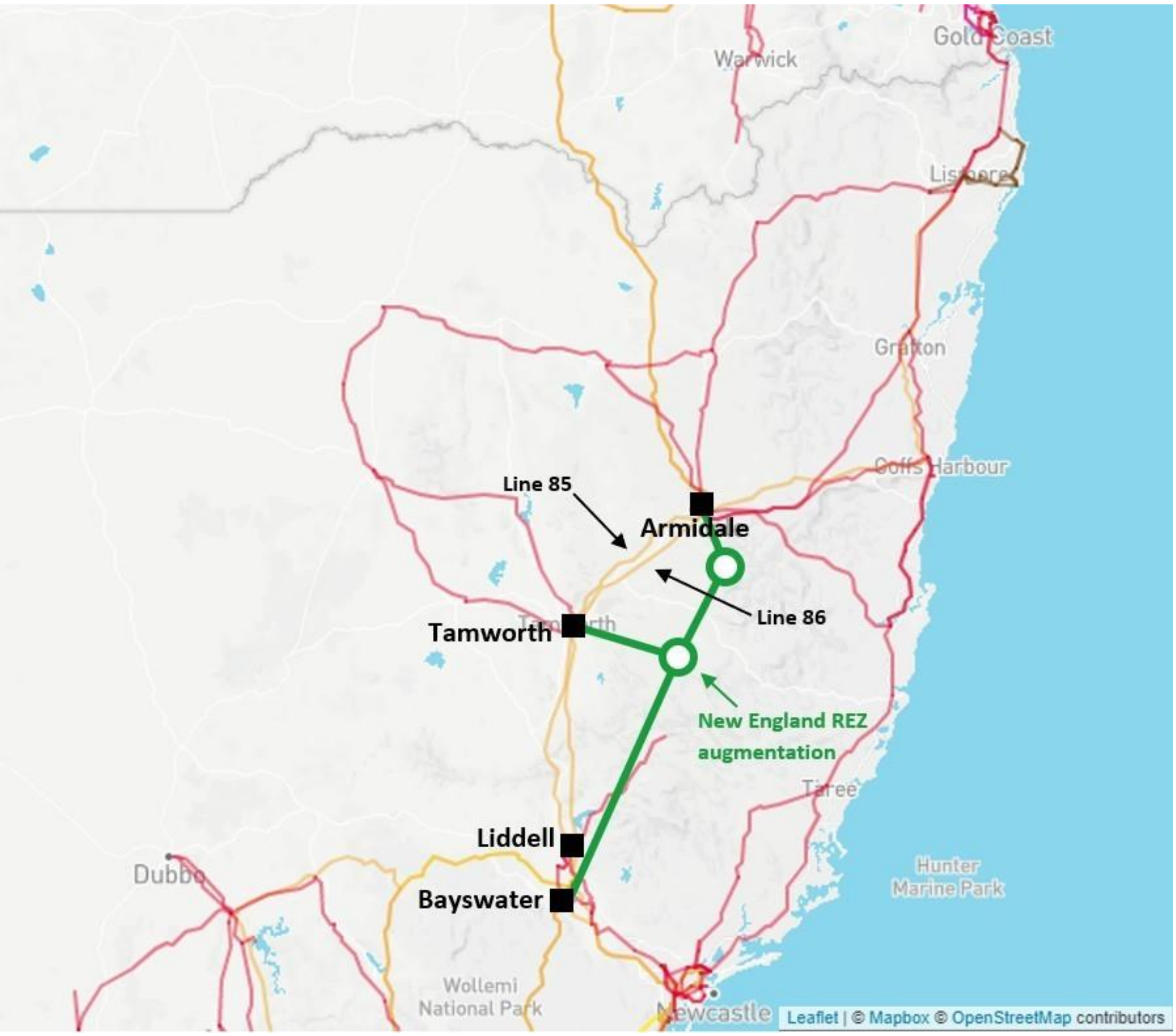
While the overall magnitude of forecast gross market benefits is reduced relative to the PADR, due to the shorter modelling horizon assumed by Transgrid, the trends and relative magnitudes between scenarios and options are similar to the PADR. Consequently, the qualitative discussion in the remainder of this section is a restatement of that in the PADR.

## 5.2 Market modelling results for Option 1C

As assumed by Transgrid, Option 1C involves replacing Line 86 in its original position over an extended period during months expected to have low market impact, based on low assumed demand at the time of the construction outages. The first partial replacement occurs in March 2028, followed by additional replacements later in the study period and outside of the modelling horizon.

The New England REZ augmentation is assumed to occur in July 2027 for all scenarios, as per AEMO's 2022 Integrated System Plan[4]. The augmentation is assumed to upgrade the network from Armidale to Bayswater by creating new 500 kV substations near Armidale and Tamworth. New 500 kV double-circuit lines are then assumed to connect the new substation south of Armidale to the new substation east of Tamworth to Bayswater. This creates a new path from NNS to NCEN, in addition to the existing 330 kV flow path from Armidale to Liddell, via Line 85 and Line 86 from Armidale to Tamworth shown in Figure 10.

Figure 10: NNS network into NCEN[13]




As per the announced NSW Electricity Infrastructure Roadmap, roughly 12 GW of additional renewable capacity is assumed to be installed in NSW by 2030. The model distributes this among NSW REZs at least-cost and it is forecast that most of this capacity will be built in the New England REZ. As advised by Transgrid, within the New England REZ, half of the additional capacity is assumed to connect to the north side of Line 86, near Armidale, and the other half will connect on the south side near Tamworth. As such, when flow is southward from NNS into NCEN, lines from Armidale to Tamworth, such as Line 86, do not need to carry all of the flow. This also means all new entrant capacity in New England is assumed to connect at or north of Tamworth. As such, lines between Tamworth and NCEN are forecast to carry more southward flow at times of high generation in New England, compared to lines from Armidale to Tamworth. When flow is southward from NNS to NCEN, most of this flow is forecast to flow across lines from Tamworth to NCEN via the two paths:

1. The existing 330 kV lines from Tamworth to Liddell, shown in Figure 10, one of which goes via Muswellbrook.

[13] AEMO map overlayed with an indicative visualisation of Transgrid's assumed New England REZ augmentation, https://www.aemo.com.au/aemo/apps/visualisations/map.html

2. The assumed double circuit 500 kV lines from Tamworth to Baywater that form stage 1 of the New England REZ augmentation and the additional double circuit 500 kV lines from Tamworth to Baywater from stage 2 of the New England REZ augmentation.

Consequently, the southward flow limit from NNS to NCEN is forecast to typically be set by transfer limits from Tamworth to NCEN, due to a combination of the N-1 thermal limits of the existing 330 kV lines and the N-1 thermal limits of the assumed 500 kV lines from the New England REZ augmentation. For the Base Case, these limits south of Tamworth are occasionally forecast to set the transfer limit from NNS to NCEN, even when Line 86 is forecast to be on outage. Essentially, after the assumed New England REZ augmentation, the N-1 limits for lines from Armidale to Tamworth (including on Line 86) are not frequently forecast to set the southerly limit for NNS to NCEN.

Transgrid has assumed the Base Case has higher forced outage rate for Line 86, compared to Option 1C. This outage rate is assumed to increase each financial year during the study period to reflect increasing unreliability as the structures age. When Line 86 is on outage, the N-0 thermal limit for Line 85 is forecast to be more likely to bind, as are the N-1 thermal limits for the assumed 500 kV lines from Armidale to Tamworth. However, the Line 86 outage rate supplied by Transgrid is not high enough to materially impact the forecast capacity expansion for the NEM during the 18-year modelling horizon. That is not to say an unplanned outage *could not* have a large impact on the system cost of the NEM before the 2040s if an outage was coincident with other factors that exacerbated its effect, such as high demand in NSW or generator outages.

As such, the added transmission reliability for Option 1C relative to the Base Case is forecast to result in negligible gross market benefits.

## 5.3 Other options outcomes

### 5.3.1 Option 1A

Option 1A is similar to Option 1C; however, the full replacement of Line 86 occurs before the New England REZ augmentation. As such, Option 1A is forecast to have similar negligible gross market benefits to that of Option 1C.

### 5.3.2 Option 1B

Transgrid has specified that Option 1B assumes the same replacement schedule as Option 1A, along with the installation of two batteries to provide VTL services that increase the N-1 thermal limits by 200 MW for the 330 kV path between Armidale and Liddell via Tamworth.

Transgrid assumed that the battery has market arbitrage capability during planned outages of Line 86. As discussed in Section 5.2, the southward flow limit from NNS to NCEN is typically set by a combination of the N-1 thermal limits for the existing 330 kV lines from Tamworth to Liddell and the assumed 500 kV lines from Tamworth to Bayswater. Increasing the N-1 thermal limit of the 330 kV lines from Tamworth to Liddell is forecast to allow more of NCEN demand to be met by generation from New England and/or Queensland, which results in positive gross market benefits for this option across all scenarios. Higher market benefits are forecast to occur in scenarios with a faster transition towards renewables, such as the Step Change and Hydrogen Superpower scenarios.

### 5.3.3 Option 3

Option 3 assumes Line 86 is rebuilt as a double circuit 330 kV option. Doing so is likely to reduce the impedance along the 330 kV flow path from Armidale to Liddell, via Tamworth. This is forecast to increase the proportion of flow across the 330 kV path from NNS to NCEN, relative to the Base Case, which reduces the proportion flowing on the assumed 500 kV route from the New England

REZ augmentation. Consequently, the N-1 thermal limits for the 330 kV lines from Tamworth to Liddell are forecast to bind earlier in the study period in Option 3 than the Base Case. This limits flow from NNS to NCEN, even though the 500 kV flow path from NNS to NCEN may still have headroom. This is estimated to result in negative gross market benefits for Option 3.

# Appendix A Methodology

## A.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 18 years from 2023-24 to 2040-41. The modelling methodology follows the RIT-T guidelines published by the AER[6].

Based on the full set of input assumptions, the TSIRP model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire modelling period, with respect to:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[14] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Units are assumed to run at their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or unplanned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, offshore wind, solar PV SAT[15], CCGT, OCGT, large-scale storage and PHES.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)[16],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES and large-scale battery storage),

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[14] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

[15] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle Gas Turbine.

[16] AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 15 July 2022.

- new entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits beyond the resource limit for wind and solar in each REZ where applicable, and PHES in each region,
- carbon budget constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in NSW through modelling of zones with intra-regional limits and loss equations. Typically, within these zones and within regions, no further detail of the transmission network is considered. An exception to this is the explicitly modelling N-0 thermal limits and N-1 constraint equations for transmission lines with the voltage level of 330 kV and above that form the intra-regional limit from NCEN to NNS. These constraints are described in Section B.2.

The model factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides how much new capacity to build in each region to deliver the least-cost market outcome.

The model meets the specified carbon budget constraints at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. An assumed energy limit is placed on coal-fired power stations where specified in AEMO's Inputs, Assumptions and Scenarios Workbook[3]. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are also modelled, which are another factor in the running cost of generators determining their economic retirements. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever the cost of supply is at or above their variable costs and operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PHES, large-scale battery storages and virtual power plants (VPPs)) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired, liquid fuel generators. Conversely, at times of low supply cost, e.g. when there is a surplus of capacity, storage hydro preserves energy and PHES and large-scale battery storage operate in pumping or charging mode.

## A.2 Reserve constraint in long-term investment planning

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

All dispatchable generators in each region are eligible to contribute to reserve (except PHES, VPPs and large-scale battery storages[17]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so

[17] PHES, VPPs and large-scale battery storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.

minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g. variability in production from variable renewable energy sources, different forced outage patterns, sub-optimal operation of storage). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size[18].

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.
- In NSW, where the major proportion of load and dispatchable generation is concentrated in the NCEN zone, the same rules are applied as for the NSW region except headroom on intra-connectors between adjacent zones does not contribute to reserve. This is because even if there is headroom on the NCEN intra-connectors, it is likely that the flows from the north and south into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

## A.3 Transmission losses in long-term investment planning

Intra and inter-regional losses are captured in the TSIRP model through explicit modelling of dynamic loss equations. More detail on these equations is given in Appendix B.

## A.4 Cost-benefit analysis

From the hourly time-sequential modelling the following categories of costs defined in the RIT-T are computed:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development.

For each option a matched no option counterfactual (referred to as the Base Case) long-term investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to the option, as defined in the RIT-T.

Each component of gross market benefits is computed annually over the 18-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[19], discounted to June 2022 at a 5.5% real, pre-tax discount rate as selected by Transgrid.

[18] Testing confirmed that this assumption does not affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.
[19] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

The forecast gross market benefits of each option need to be compared to the relevant avoided risk cost benefits (primarily bushfire risk) and option costs computed by Transgrid to determine whether there is a positive forecast net economic benefit. The determination of the forecast net economic benefit and preferred option was conducted outside of this Report by Transgrid[1] by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T guidelines as the credible option that maximises the net economic benefit across the market, compared to all other credible options[6], as identified in the PACR[1].

# Appendix B Transmission and demand

## B.1 Regional and zonal definitions

Transgrid elected to split NSW into sub-regions or zones in the modelling presented in this Report, as listed in Table 4. In Transgrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 4: Regions, zones and reference nodes

| Region | Zone | Zonal Reference Node |
|---|---|---|
| Queensland | Queensland | South Pine 275 kV |
| New South Wales | Northern New South Wales (NNS) | Armidale 330 kV |
| | Central New South Wales (NCEN) | Sydney West 330 kV |
| | South-West New South Wales (SWNSW) | Darlington Point 330 kV |
| | Canberra | Canberra 330 kV |
| | Bannaby | Bannaby 330 kV |
| | Yass | Yass 330 kV |
| | Wagga | Wagga 330 kV |
| | Lower Tumut | Lower Tumut 330 kV |
| | Snowy (Maragle) | Snowy (Maragle) 330 kV |
| | Upper Tumut | Upper Tumut 330 kV |
| Victoria | Murray | Murray 330 kV |
| | Dederang | Dederang 330 kV |
| | Victoria (VIC) | Thomastown 66 kV |
| South Australia | South Australia (SA) | Torrens Island 66 kV |
| Tasmania | Tasmania (TAS) | Georgetown 220 kV |

Dynamic loss equations are defined between reference nodes across these cut-sets. The borders of each zone defined by Transgrid or region are defined by the cut-sets listed in Table 5, as defined by Transgrid.

Table 5: Key cut-set definitions

| Border | Lines |
|---|---|
| NNS-NCEN | Line 88 Muswellbrook – Tamworth<br>Line 84 Liddell – Tamworth<br>Line 96T Hawks Nest – Taree<br>Line 9C8 Stroud – Brandy Hill |

| Border | Lines |
|---|---|
| NCEN-Canberra | Line 61 Gullen Range - Bannaby<br>Line 3W Kangaroo Valley - Capital<br>Line 4/5 Yass - Marulan<br>Line 973 Yass - Cowra<br>Line 999 Yass - Cowra<br>Line 98J Shoalhaven - Evans Lane<br>Line 28P West Tomerong - Evans Lane<br>and new HumeLink lines for each option |
| Canberra/Yass-Bannaby | Line 61 Gullen Range - Bannaby<br>Line 3W Kangaroo Valley - Capital<br>Lines 4 &5 Yass - Marulan<br>and new HumeLink lines from Maragle/Wagga to Bannaby for each option |
| Snowy cut-set | Line 01 Upper Tumut to Canberra<br>Line 2 Upper Tumut to Yass<br>Line 07 Lower Tumut to Canberra<br>Line 3 Lower Tumut to Yass |
| Wagga-SWNSW | Line 63 Wagga - Darlington Pt<br>Line 994 Yanco - Wagga<br>Line 99F Yanco - Uranquinty<br>Line 99A Finley - Uranquinty<br>Line 997/1 Corowa - Albury<br>New 330 kV double circuit from Wagga - Dinawan (after assumed commissioning of EnergyConnect)<br>New 500 kV double circuit from Wagga - Dinawan (after assumed commissioning of VNI West) |
| VIC-SWNSW | Line 0X1 Red Cliffs - Buronga<br>New Red Cliffs - Buronga (after assumed commissioning of EnergyConnect)<br>New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West) |
| VNI cut-set | Line 060 Jindera - Wodonga<br>Line 65 Upper Tumut - Murray<br>Line 66 Lower Tumut - Murray<br>VIC-SWNSW cut-set (listed above) |
| SWNSW-SA | New 330 kV double circuit from Buronga - Robertstown (after assumed commissioning of EnergyConnect) |

Table 6 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid.

Table 6: Key cut-set limits (MW)

| Cut-set | Bidirectional limit (MW) |
|---|---|
| Snowy cut-set | 3,080 |
| Snowy cut-set + HumeLink lines | 5,372 |
| Canberra/Yass- Bannaby cut-set | 4,900 |
| CAN-NCEN cut-set | 4,500 |
| Bannaby-NCEN | 4,500 |

Table 7 summarises the VNI cut-set limits across the modelling period which are consistent with AEMO's Inputs, Assumptions and Scenarios Workbook[3]. The VNI cut-set limits change with the Victorian SIPS contract ending in March 2032, and the commissioning of VNI West. The VNI West timing differs between scenarios[4] and hence the timing in VNI cut-set limit changes will also differ between scenarios.

Table 7: VNI cut-set limits[4]

| Description | Import limit (MW) | Export limit (MW) |
|---|---|---|
| Original limits | 400 all periods | 870 peak demand<br>1,000 summer<br>1,000 winter |
| Post Victorian SIPS contract | -150 peak demand[20] | Unchanged |
| Post VNI West commissioning | +1,200 all periods[20] | +1,930 all periods[20] |

## B.2 NNS-NCEN constraints

Transgrid advised that the transfer limit for NNS-NCEN is expected to be set by the thermal limits of lines near this intra-connector. As such, EY constructed thermal constraint equations for the following lines to dynamically reflect the transfer limit of NNS-NCEN:

- Line 83: 330 kV Muswellbrook to Liddell,
- Line 84: 330 kV Tamworth to Liddell,
- Line 85: 330 kV Armidale to Tamworth,
- Line 86: 330 kV Armidale to Tamworth,
- Line 88: 330 kV Tamworth to Muswellbrook,
- New 500 kV lines: All 500 kV lines as part of the New England REZ augmentations from Armidale to Tamworth to Bayswater.

Details on the thermal ratings for each line are provided in Appendix A. The methodology employed by EY to create thermal transmission constraint equations for this model is described in detail in Appendix E, and follows the method the Australian Energy Market Operator employs for developing pre-contingent constraint equations.

Two constraint types are considered: N-1 and N-0. N-1 constraints avoid the overload of the monitored line due to the outage of a single credible contingency in power system component (predominantly transmission lines), as stipulated in the NEM market rules. On the other hand, N-0 constraints avoid overloading of a line while no contingency occurs.

For the majority of hours in the modelling horizon, the pre-contingency N-0 constraint set is applied. However, a post-contingent constraint set is also created to reflect the N-1 and N-0 thermal limits in the event Line 86 is on outage. The post-contingent constraint set is modelled during the planned maintenance periods, construction periods and forced outages of Line 86. The outage timings that Transgrid assumed for Line 86, which vary between the Base Case and the different options, are presented in Table 8.

[20] The overall limit is the original limit plus the change

Table 8: Assumed outage timings for Line 86 for Base Case and all options

| Option | Planned outages | Unplanned outages |
|---|---|---|
| Base Case | 38-day maintenance outages starting 1 April 2024 during weekdays from 7am Monday to 6pm Friday. Repeated every 3 years. | Unplanned outages that last on average 96-hours. A 0.4% probability of failure in 2023-24 that increases to 4%by 2040-41. |
| Option 1A | Three 3-month construction outages, 6 days a week from 7am Monday to 3pm Saturday. The first 3-month outage is assumed to begin 1 March 2026. This is followed by the second construction outage from 1 August 2026. It is assumed that the final construction outage begins from 1 March 2027. | Before Option 1A is commissioned in 2027-28, the likelihood of an unplanned outage is identical to the Base Case. No unplanned outages after Option 1A is commissioned. |
| Option 1B | Outages are aligned with Option 1A. During planned outages Transgrid assumed that the battery has market arbitrage capability. | |
| Option 1C | A 1-month construction outage starting 1 March 2028, 6 days a week from 7am Monday to 3pm Saturday. A 3-month construction outage starting 1 March 2045, 6 days a week from 7am Monday to 3pm Saturday. Additional construction outages outside of the modelling horizon. | Before the first construction outage, the likelihood of an unplanned outage is identical to the Base Case. Transgrid has assumed that the staged replacement of Line 86 result in the likelihood of an unplanned outage being 0.4% by 2040-41, compared to 10% in the Base Case by this time. |
| Option 3 | Planned 7-day outage at the end of June 2027. | Before Option 3 is commissioned in 2027-28, the likelihood of an unplanned outage is identical to the Base Case. |

## B.3 Interconnector and intra-connector loss models

Dynamic loss equations for today's network are generally sourced from AEMO's *Regions and Marginal Loss Factors*.[21] Dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g. NNS-NCEN, SA-SWNSW (EnergyConnect), Bannaby-NCEN, Wagga-SWNSW,
- when interconnector definition changes with the addition of new reference nodes e.g. VNI now spans VIC-SWNSW and VIC-DED instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled e.g. VNI West, QNI Connect and Marinus Link.
- for Canberra equivalent lines, using their resistance.

The network snapshots to compute the loss equations were provided by Transgrid.

## B.4 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 9. The following interconnectors are included in the left-hand side of constraints which may restrict them below the notional limits specified in this table:

[21] AEMO, *Marginal Loss Factors for the 2018-19 Financial Year*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries. Accessed 15 July 2022.

► Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW, respectively. The model will dispatch them to minimise costs.

Table 9: Notional interconnector capabilities, excluding VNI[22] (sourced from AEMO 2022 ISP[4])

| Interconnector (From node – To node) | Import[23] notional limit | Export[24] notional limit |
|---|---|---|
| QNI | 1,205 MW peak demand<br>1,165 MW summer<br>1,170 MW winter | 685 MW peak demand<br>745 MW summer/winter |
| QNI Connect 1[25] | 2,285 MW peak demand<br>2,245 MW summer<br>2,250 MW winter | 1,595 MW peak demand<br>1,655 MW summer/winter |
| QNI Connect 2[25] | 3,085 MW peak demand<br>3,045 MW summer<br>3,050 MW winter | 2,145 MW peak demand<br>2,205 MW summer/winter |
| Terranora (NNS-SQ) | 130 MW peak demand<br>150 MW summer<br>200 MW winter | 0 MW peak demand<br>50 MW summer/winter |
| EnergyConnect (SWNSW-SA) | 800 MW | 800 MW |
| Heywood (VIC-SA) | 650 MW (before EnergyConnect)<br>750 MW (after EnergyConnect) | 650 MW (before EnergyConnect)<br>750 MW (after EnergyConnect) |
| Murraylink (VIC-SA) | 200 MW | 220 MW |
| Basslink (TAS-VIC) | 478 MW | 478 MW |
| Marinus Link (TAS-VIC) | 750 MW for the first leg and 1,500 MW after the second leg | 750 MW for the first leg and 1,500 MW after the second leg |

NSW has been split into zones with the following limits imposed between the zones defined in Table 10.

Table 10: Intra-connector notional limits imposed in modelling for NSW (sourced from Transgrid)

| Intra-connector (From node – To node) | Import notional limit | Export notional limit |
|---|---|---|
| NCEN-NNS | Notional limit not applicable. Transgrid has advised that the import limit for NCEN-NNS will be set by the explicitly modelled thermal limits discussed in Section B.4 | 1,377 MW (after QNI Minor)<br>Limit will increase after NEW England REZ augmentations as mentioned in the 2022 ISP[4] |

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[22] VNI cut-set limits presented in Table 7.

[23] Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. import along QNI implies southward flow and import along Heywood implies eastward flow.

[24] Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. export along QNI implies northward flow and export along Heywood implies westward flow.

[25] AEMO, *Appendix 5. Network investments*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 15 July 2022.

| Intra-connector (From node - To node) | Import notional limit | Export notional limit |
|---|---|---|
| Wagga-SWNSW | 300 MW (before EnergyConnect)<br>1,100 MW (after EnergyConnect)<br>2,100 MW (after HumeLink)<br>3,000 MW (after VNI West) | 500 MW (before EnergyConnect)<br>1,300 MW (after EnergyConnect)<br>2,100 MW (after HumeLink)<br>3,000 MW (after VNI West) |

## B.5 Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical operational demand and the estimated rooftop PV generation based on historical monthly rooftop PV capacity and solar insolation,
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 11,
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

Figure 11: Sequence of demand reference years applied to forecast

| Modelled year | Reference year |
|---|---|
| 2023-24 | 2014-15 |
| 2024-25 | 2015-16 |
| 2025-26 | 2016-17 |
| 2026-27 | 2017-18 |
| 2027-28 | 2018-19 |
| 2028-29 | 2010-11 |
| 2029-30 | 2011-12 |
| 2030-31 | 2012-13 |
| 2031-32 | 2013-14 |
| 2032-33 | 2014-15 |
| 2033-34 | 2015-16 |
| 2034-35 | 2016-17 |
| 2035-36 | 2017-18 |

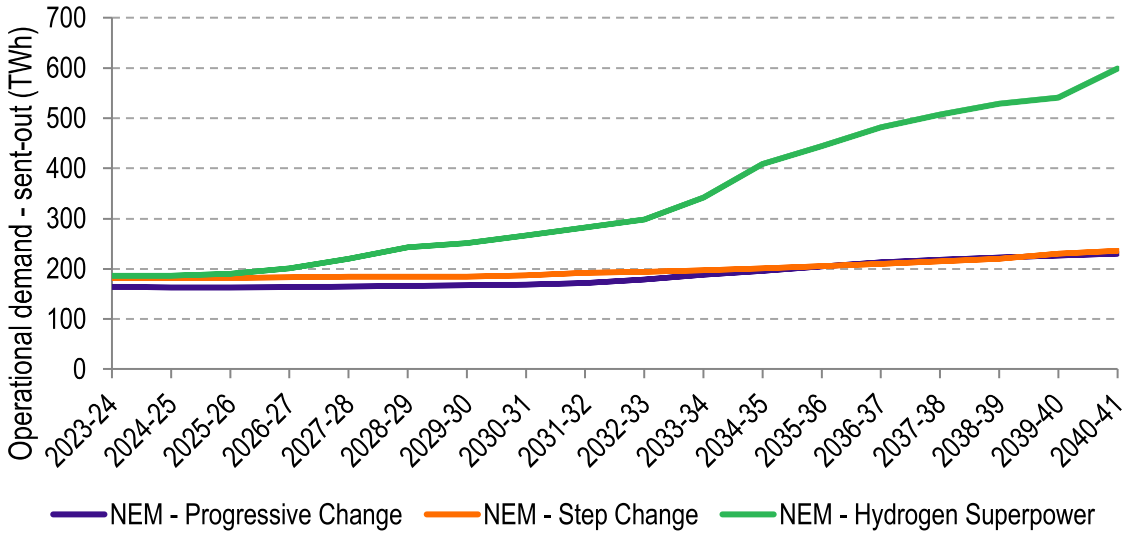
| Modelled year | Reference year |
|---|---|
| 2036-37 | 2018-19 |
| 2037-38 | 2010-11 |
| 2038-39 | 2011-12 |
| 2039-40 | 2012-13 |
| 2040-41 | 2013-14 |

This method takes into consideration the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to the assumed rooftop PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Section C.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

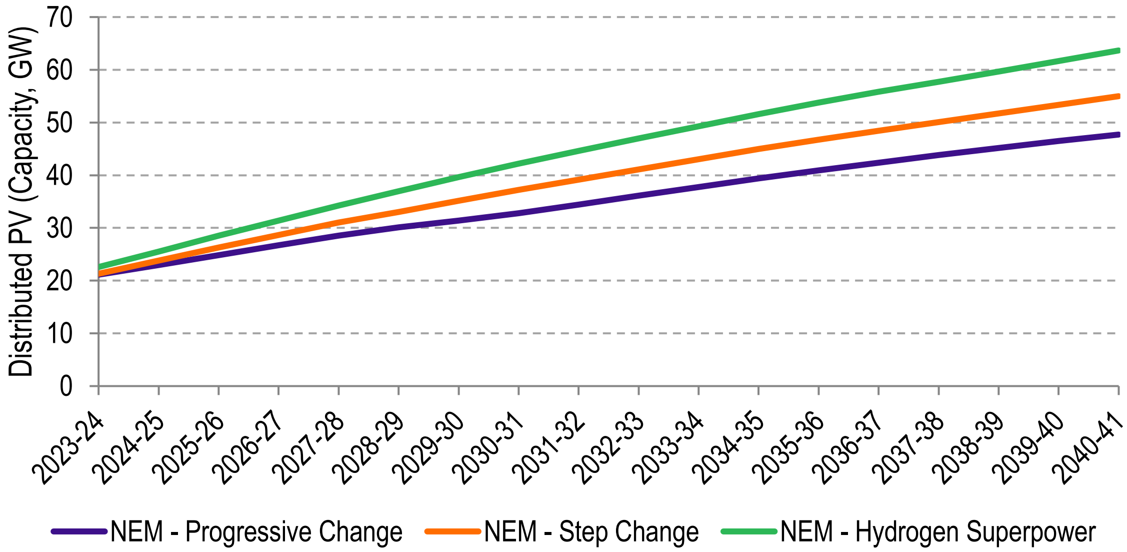
Transgrid selected demand forecasts from the ESOO 2021[26], which are used as inputs to the modelling. Figure 12 and Figure 13. shows the NEM operational energy and distributed PV for the modelled scenarios.

Figure 12: Annual operational demand in the modelled scenarios for the NEM[26]




[26] AEMO, August 2021, *NEM Electricity Statement of Opportunities (ESOO),* Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 15 July 2022.

Figure 13: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[26]




For NSW, the ESOO 2021 demand forecasts are split into the various NSW zones that have been defined by Transgrid, as described in Section B.1. Transgrid obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which are used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in NSW.

# Appendix C Supply

## C.1 Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each option. The source of this list is based on AEMO's Inputs, Assumptions and Scenarios workbook[3] and the AEMO NEM Generation Information June 2022 workbook[5] existing, committed and anticipated projects, including batteries, are included.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[27]. The methodology for each category of wind and solar project is summarised in Table 11 and explained further in this section of the Report.

Table 11: Summary of wind and solar availability methodology

| Technology | Category | Capacity factor methodology | Reference year treatment |
|---|---|---|---|
| Wind | Existing | Specific long-term target based on nine-year average in AEMO ESOO 2019 traces[28] where available, otherwise past meteorological performance. | Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts. |
| | Committed new entrant | Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's Inputs, Assumptions and Scenarios workbook[3]. | |
| | Generic REZ new entrants | Reference year specific targets based on AEMO's Inputs, Assumptions and Scenarios workbook[3]. One high quality option and one medium quality trace per REZ. | |
| Solar PV FFP | Existing | Annual capacity factor based on technology and site-specific solar insolation measurements. | Capacity factor varies with reference year based on historical, site-specific insolation measurements. |
| Solar PV SAT | Existing | | |
| | Committed new entrant | Reference year specific targets based on capacity factor of nearest REZ, in AEMO's ISP Inputs, Assumptions and Scenarios workbook[3]. | |
| | Generic REZ new entrant | Reference year specific targets based on AEMO Inputs, Assumptions and Scenarios workbook[3]. | |
| Rooftop PV and small non-scheduled solar PV | Existing and new entrant | Long-term average capacity factor based on AEMO Inputs, Assumptions and Scenarios workbook[3]. | Capacity factor varies with reference year based on historical insolation measurements. |

[27] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 15 July 2022.

[28] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Accessed 15 July 2022.

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive), and synchronised with the hourly shape of demand. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 11 from Section B.5.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[29] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2019 ESOO[30] and 2022 ISP assumptions[3,4] for each REZ (new entrant wind farms, as listed in Table 12).

The availability profiles for solar are derived using solar irradiation data downloaded from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or target AEMO's capacity factor for each REZ (generic new entrant solar farms as listed in Table 12).

Table 12: 2021 IASR REZ wind and solar average capacity factors over AEMO's twelve reference years[3]

| Region | REZ | Wind | | Solar SAT |
|---|---|---|---|---|
| | | High quality | Medium quality | |
| Queensland | Far North Queensland | 54% | 48% | 27% |
| | North Queensland Clean Energy Hub | 43% | 36% | 30% |
| | Northern Queensland | Tech not available | Tech not available | 28% |
| | Isaac | 37% | 31% | 29% |
| | Barcaldine | 33% | 31% | 32% |
| | Fitzroy | 38% | 33% | 28% |
| | Wide Bay | 32% | 30% | 27% |
| | Darling Downs | 39% | 34% | 28% |
| | Banana | 31% | 28% | 29% |
| New South Wales | North West NSW | Tech not available | Tech not available | 29% |
| | New England | 39% | 38% | 26% |
| | Central West Orana | 37% | 34% | 27% |
| | Broken Hill | 33% | 31% | 30% |

29 As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 3 May 2022.

30 AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Accessed 15 July 2022.

| Region | REZ | Wind | | Solar SAT |
|---|---|---|---|---|
| | | High quality | Medium quality | |
| | South West NSW | 30% | 30% | 27% |
| | Wagga Wagga | 28% | 27% | 26% |
| | Cooma-Monaro | 43% | 41% | Tech not available |
| Victoria | Ovens Murray | Tech not available | Tech not available | 24% |
| | Murray River | Tech not available | Tech not available | 27% |
| | Western Victoria | 42% | 37% | 23% |
| | South West Victoria | 41% | 39% | Tech not available |
| | Gippsland[31] | 40% | 35% | 20% |
| | Central North Victoria | 33% | 31% | 26% |
| South Australia | South East SA | 40% | 37% | 23% |
| | Riverland | 29% | 28% | 27% |
| | Mid-North SA | 39% | 37% | 26% |
| | Yorke Peninsula | 37% | 36% | Tech not available |
| | Northern SA | 37% | 35% | 28% |
| | Leigh Creek | 41% | 40% | 31% |
| | Roxby Downs | Tech not available | Tech not available | 30% |
| | Eastern Eyre Peninsula | 40% | 38% | 25% |
| | Western Eyre Peninsula | 40% | 38% | 27% |
| Tasmania | North East Tasmania | 46% | 44% | 22% |
| | North West Tasmania[32] | 51% | 46% | 19% |
| | Central Highlands | 56% | 54% | 21% |

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's Inputs, Assumptions and Scenarios workbook[3].

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.

[31] Gippsland has an option for offshore wind with an average capacity factor of 46%.

[32] North West Tasmania has an option for offshore wind with an average capacity factor of 50%.

- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

## C.2 Generator forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based the AEMO Inputs, Assumptions and Scenarios workbook[3].

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and the various upgrade options. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO Inputs, Assumptions and Scenarios workbook[3].

## C.3 Generator technical parameters

All technical parameters are as detailed in the AEMO Inputs, Assumptions and Scenarios workbook[3] for AEMO's long-term planning model, except as noted in the Report.

## C.4 Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must-run generation is dispatched whenever available at least at its minimum load. In line with the AEMO Inputs, Assumptions and Scenarios workbook[3]. Maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75% is assumed for NSW coal, as per the AEMO Inputs, Assumptions and Scenarios workbook[3].

## C.5 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the AEMO Inputs, Assumptions and Scenarios workbook[3], a minimum load of 46% of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

## C.6 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section C.1.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the marginal cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

## C.7 Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO Inputs, Assumptions and Scenarios workbook and the median hydro climate factor trajectory for the respective scenario applied[3]. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input Assumptions and Scenario workbook for Project Marinus PACR[33].

[33] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR.* Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 15 July 2022

# Appendix D Assumed thermal ratings for modelled lines

Table 13 describes the different operating conditions used to determine Transgrid's assumed thermal rating for a given hour.

Table 13: Description of different operating conditions

| Operating condition | Description |
|---|---|
| Autumn/Spring day | Either from the beginning of March to the end of May or from the beginning of September to the end of November. Between 7am and 7pm. |
| Autumn/Spring night | Either from the beginning of March to the end of May or from the beginning of September to the end of November. Between 7pm and 7am. |
| Summer day | From the beginning of December to the end of February. Between 6am and 8pm. |
| Summer night | From the beginning of December to the end of February. Between 8pm and 6am. |
| Winter day | From the beginning of June to the end of August. Between 8am and 6pm. |
| Winter night | From the beginning of December to the end of February. Between 6pm and 8am. |
| Line 86 outage before NE | When Line 86 is assumed to be on outage. Before the assumed commissioning of New England REZ augmentation stage 1 in July 2027. |
| All periods | Applies to all periods. |

Table 14 presents a summary of the assumed thermal limits provided by Transgrid for each of the modelled lines for a power factor of 0.95. These are used by EY to create thermal transmission constraint equations for this model, which is described in detail in Appendix E

Table 14: Thermal limits for monitored lines

| Line | Description | Operating condition | Thermal limit (MW) |
|---|---|---|---|
| Line 83 | 330 kV Muswellbrook to Liddell | Autumn/Spring day | 966 |
| | | Autumn/Spring night | 1,004 |
| | | Summer day | 934 |
| | | Summer night | 994 |
| | | Winter day | 998 |
| | | Winter night | 1,026 |
| Line 84 | 330 kV Tamworth to Liddell | Autumn/Spring day | 882 |
| | | Autumn/Spring night | 950 |
| | | Summer day | 847 |
| | | Summer night | 923 |
| | | Winter day | 945 |

| Line | Description | Operating condition | Thermal limit (MW) |
|---|---|---|---|
| | | Winter night | 978 |
| Line 85 | 330 kV Armidale to Tamworth | Autumn/Spring day | 882 |
| | | Autumn/Spring night | 950 |
| | | Summer day | 847 |
| | | Summer night | 923 |
| | | Winter day | 945 |
| | | Winter night | 978 |
| | | Line 86 outage before NE | 700 |
| Line 86[34] | 330 kV Armidale to Tamworth | Autumn/Spring day | 836 |
| | | Autumn/Spring night | 858 |
| | | Summer day | 798 |
| | | Summer night | 847 |
| | | Winter day | 864 |
| | | Winter night | 885 |
| Line 88 | 330 kV Tamworth to Muswellbrook | Autumn/Spring day | 882 |
| | | Autumn/Spring night | 950 |
| | | Summer day | 847 |
| | | Summer night | 923 |
| | | Winter day | 945 |
| | | Winter night | 978 |
| New 500 kV lines | All 500 kV lines as part of the New England REZ augmentations from Armidale to Tamworth to Bayswater | All periods | 3,117 |

[34] Transgrid has advised these thermal limits apply for the existing Line 86 apply for the Base case and each of the options. For Option 3, both new 330 kV lines from Armidale to Tamworth also use these thermal limits.

# Appendix E Constraint formulation

EY's model was configured such that the constraint equation data set includes mapping of all existing and new generator connection points to constraint equation terms as appropriate for the thermal limits of the 330 kV and above lines from Armidale to Tamworth to Liddell and Bayswater for the network topography assumed by Transgrid.

To model network congestion for the assumed network upgrades provided by Transgrid as well as the connection of new entrant generation, EY has constructed custom thermal constraint equations. These custom equations are constructed using an approach which is consistent with AEMO's constraint creation processes and are used to assess the potential N-1 and N-0 limits near Line 86.

## E.1 Constraint formulation

The objective of a thermal constraint equation is to prevent overloading of any transmission network element. N-0 constraints are formulated to prevent the overloading of transmission network elements during system normal operation, while N-1 constraints are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a transmission network element). N-1 constraints are enforced pre-contingently, that is, at all times.

In the NEM, the elements within a thermal constraint equation can be categorised as follows:

- generator terms and coefficients,
- interconnector terms and coefficients,
- demand coefficient,
- constant term.

NEM thermal constraint equations are formulated such that the sum of terms on the left-hand side (LHS) must be less than or equal to the sum of terms on the right-hand side (RHS). Generation and interconnector terms are typically assigned to the LHS, while constant and demand terms are typically assigned to the RHS.

## E.2 Description of a binding constraint

If, before dispatch, the desirable combination of generator bidding and demand would theoretically lead to a constraint equation violating (i.e., the LHS is exceeding the RHS indicating a potential network element overload) then generator output, interconnector flow or load must be curtailed below the desirable dispatch level to reduce the LHS. Curtailment is based on the cost of that curtailment, with the least cost solution being applied. The cost of curtailment is an outcome of both the magnitude of the coefficient (a multiplier which determines the unit's impact on the constraint) and the generator/load/interconnector's cost.

If two generators have the same SRMC, the generator with the higher LHS coefficient is curtailed first. If two generators have the same LHS coefficient, the generator with the higher SRMC is curtailed first.

## E.3 N-0 generator coefficients

For an N-0 constraint, generator coefficients in a constraint equation are determined using Power Transfer Distribution Factors (PTDFs). The PTDF is a sensitivity measure of the power flow on a transmission element connecting bus $j$ to bus $k$ with respect to a generator injection at bus $m$. The coefficient for a generator connected at bus $m$ can be calculated by differentiating the power flow across a monitored element connecting bus $j$ to bus $k$ with respect to the power injection at bus $m$, that is:

$$PTDF_{G_m,j\to k} = \frac{dF_{j\to k}}{dP_{G_m}}$$

Where $P_{G_m}$ is the power injected by a generator at bus $m$ and $F_{j\to k}$ is the power flow across the monitored element from bus $j$ to bus $k$.

An underlying assumption is that the Regional Reference Node (RRN) will absorb any incremental injection at bus $m$. Therefore, the PTDFs can be viewed as the contribution of a small amount of power injection at bus $m$ on the power flow across element connecting bus $j$ to bus $k$ to supply a small increase in demand at the RRN.

Generator coefficients defined this way will depend purely on the location of the RRN and the assumed system network topology provided by Transgrid. They will not be influenced by the regional demand or generation dispatch across the system.

## E.4 N-0 interconnector coefficients

Similar to the calculation outlined in the previous section, interconnector coefficients are determined using PTDFs associated with power injection at the regional boundary buses. That is, the coefficient for an interconnector at the regional boundary bus $n$ for a monitored element connecting bus $j$ to bus $k$ is defined as:

$$PTDF_{IC_n,j\to k} = \frac{dF_{j\to k}}{dP_{IC_n}}$$

Where $P_{IC_n}$ is the interconnector power injection (positive for importing power and negative for exporting power) from neighbouring regions into bus $n$.

## E.5 N-1 redistribution factor

N-1 constraints are designed to pre-contingently curtail generation to ensure that following a single credible contingency, the resulting power flows do not exceed thermal limits. When a transmission element is de-energised, the power flowing through the de-energised element redistributes across the remaining transmission elements. The proportion of power flow from a contingent element that flows through a monitored element is known as the redistribution factor. Redistribution factors can be approximated using Line Outage Distribution Factors (LODF). For a monitored network element connecting bus $\boldsymbol{j}$ to bus $\boldsymbol{k}$ and a contingent network element connecting bus $\boldsymbol{h}$ to bus $\boldsymbol{i}$, the LODF can be defined as:

$$LODF_{j\to k,h\to i} = \frac{\Delta F_{j\to k}}{F_{h\to i}} \ when \ F_{h\to i} \to 0$$

Where $F_{j\to k}$ is flow on the monitored element and $F_{h\to i}$ is flow on the contingent element.

## E.6 N-1 generator and interconnector coefficients

With the definitions provided above, the coefficient for a generator at bus $m$ in an N-1 constraint equation with a monitored network element connecting bus $j$ to bus $k$ following outage of a contingent network element connecting bus $h$ to bus $i$ can be defined as:

$$PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to i}$$

Similarly, for interconnectors:

$$PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to i}$$

## E.7 Demand coefficients

Demand coefficients correspond to the contribution of regional demand towards the power flow on a monitored network element. To calculate the nodal demand coefficient for a monitored network element connecting bus $j$ to bus $k$ for time-interval $t$, EY calculate the derivative of the power flow from bus $j$ to bus $k$ with respect to the nodal *as generated* demand (as delivered demand plus system losses and auxiliary loads), denoted by $D_{r,t}$ that is:

$$Coeff_{D_{r,t},j\to k} = \frac{dF_{j\to k}}{dD_{r,t}}$$

This value can be approximated accurately by scaling the regional demand up by a small amount (less than 1%) and dividing the difference in power flow by the difference in regional demand, that is:

$$Coeff_{D_{r,t},j\to k} = \frac{F'_{j\to k} - F_{j\to k}}{D'_{r,t} - D_{r,t}} = \frac{\Delta F_{j\to k}}{\Delta D_{r,t}}$$

Where $F'_{j\to k}$ is the observed flow associated with the scaled regional demand, and $D'_{r,t}$ is the scaled up regional demand. The distribution of demand throughout NSW for time-interval $t$, is based on the location of large industrial loads and half-hourly connection point scaling factors provided to EY by Transgrid, to determine the proportion of regional demand at each connection point.

The methodology described above assumes that the change in the regional demand is balanced by power injection at the RRN. Furthermore, since the demand is predominantly scaled up in proportion to the historical regional demand distribution, different demand distributions from different system operating states will still result in different demand coefficients.

## E.8 Constant term

The constant term corresponds predominantly to the thermal line rating (in MW) of the monitored element, with an additional offset referred to as the $ConstantEx\ Rating$, that is:

$$Constant\ Term = Thermal\ Rating_{j\to k,MW} + ConstantEx\ Rating_{j-k}$$

Thermal line ratings are typically given in MVA. To convert MVA ratings to MW ratings, a power factor (PF) of 0.95 has been assumed (unless otherwise specified) and equates the MW ratings as:

$$Thermal\ Rating_{j\to k,MW} = PF \cdot Thermal\ Rating_{j\to k,MVA}$$

The $ConstantEx\ Rating$ value is required in addition to the thermal rating to take into account the difference in power flow between AC and DC solutions (since generator coefficients are calculated based on a DC load flow solution) and the contribution (equivalent PTDF) of all other generators with small coefficients which are not explicitly included in the constraint equation. This value is computed as the difference between the calculated flow across the monitored element based on generator and demand coefficients obtained and the actual AC power flow solution. For a system with *M* generator connection points and *N* interconnector boundaries and *R* load connection points, the $ConstantEx\ Rating$ value for the monitored element connecting bus $j$ to bus $k$ is calculated as:

$$
\begin{aligned}
ConstantEx\ Rating_{j-k} \quad = \quad & \sum_{m=1}^{M} P_{G_m} \cdot PTDF_{G_m,j\to k} \\
& + \sum_{n=1}^{N} P_{IC_n} \cdot PTDF_{IC_n,j\to k} \\
& + \sum_{r=1}^{R} D_{r,t} \cdot Coeff_{D_{r,t},j\to k} \\
& - F_{j-k}
\end{aligned}
$$

## E.9 Formulating a constraint equation

Having defined the key elements, a constraint equation is formulated with generation and interconnector terms on the LHS and constant and demand terms on the RHS as:

$$
\begin{aligned}
& \sum_{m=1}^{M} P_{G_m} \cdot \left(PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to k}\right) & & Thermal\ Rating_{MW} \\
& + \sum_{n=1}^{N} P_{IC_n} \cdot \left(PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to k}\right) \quad \leq & & + \sum_{r=1}^{R} Coeff_{D_{r,t},j\to k} \cdot D_{r,t} \\
& & & + ConstantEx\ Rating
\end{aligned}
$$

Further to this, AEMO has specified that in cases where the coefficient of a term on the LHS is relatively small then the risk of NEMDE choosing sub-optimal dispatch decisions may exist. To avoid such situations a rule has been adopted where LHS terms shall not have coefficients less than |0.07|. This can be achieved by:

- Scaling the constraint equation such that all coefficients for LHS terms are not less than 0.07 provided that the absolute value of largest coefficient of any LHS term does not then exceed 1. This is to ensure that the effective violation penalties of network constraint equations grade adequately with other constraints in the dispatch algorithm.
- If after scaling, terms with such small coefficients remain they are typically moved to the RHS. However, as the TSIRP is a time sequential model, generators and interconnectors terms cannot be modelled on the RHS of the constraint which uses the previous period dispatch. To overcome this, the modelling keeps them on the LHS. To avoid sub optimality, all lower than 0.03 coefficients are removed. If the previous dispatch interval was independent of the current dispatch interval, these terms could be moved to the RHS.

EY has adopted the above methodology as a final step in the formulation of constraint equations.

# Appendix F Glossary of terms

| Abbreviation | Meaning |
|---|---|
| AEMO | Australian Energy Market Operator |
| AC | Alternating Current |
| CAN | Canberra (NEM zone) |
| CAPEX | Capital Expenditure |
| CCGT | Combined-Cycle Gas Turbine |
| DCLF | DC Load Flow |
| DER | Distributed Energy Resources |
| DSP | Demand side participation |
| DUID | Dispatchable Unit Identifier |
| FFP | Fixed Flat Plate |
| FOM | Fixed Operation and Maintenance |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| ISP | Integrated System Plan |
| LODF | Line Outage Distribution Factor |
| LRET | Large-scale Renewable Energy Target |
| Large-scale battery | Large-scale battery storage (as distinct from behind-the-meter battery storage) |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCEN | Central New South Wales (NEM zone) |
| NEM | National Electricity Market |
| NNS | Northern New South Wales (NEM zone) |
| NPV | Net Present Value |
| NSW | New South Wales |
| OCGT | Open-Cycle Gas Turbine |
| PADR | Project Assessment Draft Report |
| PACR | Project Assessment Conclusion Report |
| PF | Power Factor |
| POE | Probability of Exceedence |
| PSCR | Project Specification Consultation Report |

| Abbreviation | Meaning |
| --- | --- |
| PHES | Pumped Hydro Energy Storage |
| PTDF | Power Transfer Distribution Factor |
| PV | Photovoltaic |
| QNI | Queensland-New South Wales interconnector |
| QRET | Queensland Renewable Energy Target |
| REZ | Renewable Energy Zone |
| RIT-T | Regulatory Investment Test for Transmission |
| RRN | Regional Reference Node |
| SA | South Australia |
| SAT | Single Axis Tracking |
| SRMC | Short-Run Marginal Cost |
| SWNSW | South West New South Wales (NEM zone) |
| SWVIC | South West Victoria (REZ) |
| TAS | Tasmania |
| TSIRP | Time-sequential integrated resource planner |
| TW | Terawatt |
| TWh | Terawatt-hour |
| USE | Unserved Energy |
| VCR | Value of Customer Reliability |
| VIC | Victoria |
| VNI | Victoria-New South Wales Interconnector |
| VOM | Variable Operation and Maintenance |
| VRET | Victoria Renewable Energy Target |
| VPP | Virtual Power Plant |

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