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Appendix 3d: Gross market benefits - EY

Gross market benefit assessment of Project EnergyConnect

Transgrid

24 February 2025

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Release Notice

Ernst & Young ("**EY**") was engaged on the instructions of NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Network Operations Trust (Transgrid or the"**Client**") to undertake market modelling of system costs and benefits to forecast the gross benefits of Project Energy Connect (the "**Project**"), in accordance with purchase order dated 9 September 2024 ("the **Agreement**").

The results of EY's work, including the assumptions and qualifications made in preparing the report, are set out in EY's report dated 24 February 2025 ("**Report**"). You should read the Report in its entirety including any disclaimers and attachments. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

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24 February 2025

[redacted]
Transgrid
180 Thomas Street
Sydney, NSW, 2000

Market modelling of system costs and benefits of Project Energy Connect

Dear [redacted]

In accordance with the purchase order dated 9 September 2025 ("Agreement"), Ernst & Young ("we" or "EY") has been engaged by NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Network Operations Trust ("you", "Transgrid" or the "Client") to undertake market modelling of system costs and benefits to forecast the gross benefits of Project Energy Connect (the "Project").

The enclosed report (the "Report") sets out the outcomes of our work. You should read the Report in its entirety. A reference to the report includes any part of the Report.

Purpose of our Report and restrictions on its use

Please refer to a copy of the Agreement for the restrictions relating to the use of our Report. We understand that the deliverable by EY will be used for the purpose of Transgrid's own internal management analysis, and for release to the Australian Energy Regulator and public, (the "Purpose").

This Report was prepared on the specific instructions of Transgrid solely for the Purpose and should not be used or relied upon for any other purpose.

This Report and its contents may not be quoted, referred to or shown to any other parties except as provided in the Agreement. We accept no responsibility or liability to any person other than to Transgrid or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk. Third parties seeking a copy of this Report will require permission from EY, and will be required to sign an access letter in the format agreed to between EY and Transgrid.

Nature and scope of our work

The scope of our work, including the basis and limitations, are detailed in our Agreement and in this Report.

Our work commenced on 26 August 2024 and was completed on 24 November 2024. Therefore, our Report does not take account of events or circumstances arising after 24 November 2024 and we have no responsibility to update the Report for such events or circumstances.

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This modelling considers only a three combinations of input assumptions relating to future conditions, which may not necessarily represent actual or most likely future conditions. Additionally, modelling inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility for the achievement of projected outcomes, if any.

We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on your future course of action. We provide no assurance that the scenario we have modelled will be accepted by any relevant authority or third party.

Our conclusions are based, in part, on the assumptions stated and on information provided by Transgrid on and before 24 November 2024. The modelled outcomes are contingent on the collection of assumptions as agreed with the Client and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by Transgrid.

In the preparation of this Report we have considered and relied upon information from a range of sources believed after due enquiry to be reliable and accurate. We have no reason to believe that any information supplied to us, or obtained from public sources, was false or that any material information has been withheld from us.

We do not imply and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose. However, we have evaluated the information provided to us by Transgrid as well as other parties through enquiry, analysis and review and nothing has come to our attention to indicate the information provided was materially mis-stated or would not afford reasonable grounds upon which to base our Report.

This letter should be read in conjunction with our Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact [redacted] on [redacted]

Yours sincerely

[redacted]

[redacted]
Partner

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1. Executive Summary

Transgrid engaged EY to undertake market modelling of system costs to forecast the gross market benefits to the National Electricity Market (NEM) of additional transfer capacity between South Australia, New South Wales and Victoria with Project EnergyConnect (PEC). The proposed network augmentations comprise of a new 330 kV interconnector between New South Wales and South Australia. The interconnector runs from Robertstown in South Australia to Wagga Wagga in New South Wales, via the northernmost section of the transmission network in Victoria. It traverses between east and west, linking the REZs of Riverland, Murray River, and South-West New South Wales, providing additional transmission connection capacity to these REZs.

PEC is to be completed in two stages. Stage 1 comprises an initial 275 kV connection between Robertstown and a new substation at Bundey and a 330 kV connection between Bundey and Buronga, which is expected to release 150 MW of transfer capacity between New South Wales and South Australia. PEC Stage 1 is currently undergoing inter-network testing. Stage 2 completes the interconnector with a 330 kV connection between Buronga to a new switching station at Dinawan, 500 kV connection between Dinawan and Wagga Wagga operated at 330 kV until VNI West is complete and a 220 kV line between Buronga and Red Cliffs, and is expected to release the full 800 MW of transfer capacity between New South Wales and South Australia (650 MW incremental to Stage 1).

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. EY computed the least-cost generation dispatch and capacity development plan for the NEM for three scenarios: Step Change, Progressive Change and Green Energy Exports. These combine input assumptions which vary for each scenario including:

- Policies, costs and generator technical parameters from the Australian Energy Market Operator's (AEMO) Inputs, Assumptions and Scenarios Report (IASR) workbook[1] (which details input assumptions to the 2024 Integrated System Plan[2] (ISP)).
- Operational demand projections consistent with the 2023 Electricity Statement of Opportunities (ESOO)[3], which was also input to the Draft 2024 ISP.
- Assumed timing of major transmission upgrades based on the 2024 ISP outcomes[4] or earliest in-service date advised by proponent where this is later that the ISP outcome.
- Coal-fired generator expected retirement dates based on the 2024 ISP outcomes[4], with an announced delay in Eraring's retirement until Aug 2027[5].

Common policy settings across all three scenarios as per the 2024 IASR workbook[1] include the Federal Government's 82% renewables target by 2030, federal Capacity Investment Scheme (CIS) renewable capacity and dispatchable capacity targets, New South Wales Electricity Infrastructure Roadmap target, Queensland Renewable Energy Target, South Australia Hydrogen Jobs Plan, Tasmanian Renewable Energy Target, Victorian Renewable Energy Target, Victorian Energy Storage Target and the Victorian Offshore Wind Target.

[1] AEMO, July 2024, *2024 ISP Inputs and Assumptions Workbook v6.0*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-isp-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 24 October 2024.
[2] AEMO, 26 June 2024, *2024 ISP*. Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 24 October 2024.
[3] AEMO, *Electricity Forecasting Data Portal*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 October 2024
[4] AEMO, June 2024, *2024 ISP Generation and storage outlook*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/supporting-materials/2024-isp-generation-and-storage-outlook.zip?la=en. Accessed 25 October 2024.
[5] AEMO, 29 July 2024, *NEM Generation Information July 2024. 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 24 October 2024.

Input assumptions to the three scenarios are consistent with the following scenario narratives:

- The Step Change: Decarbonisation efforts that support Australia's share in limiting global temperature rise to below 2˚C compared to pre-industrial levels. This scenario uses significant transport electrification, as well as developing hydrogen production or low emissions alternatives to support domestic industrial loads. This is a refinement of the 2022 AEMO IASR Step Change scenario[6].
- Progressive Change: Aims to meet Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050[7]. However, this scenario is hindered by a reduction in industrial loads, higher technology costs and supply chain challenges. Assumed demand across the NEM is lowest in this scenario.
- Green Energy Exports: Very strong decarbonisation domestically and globally, including the strong use of electrification, green hydrogen and biomethane. This is a refinement of the 2022 AEMO IASR[6] Hydrogen Superpower scenario. Assumed demand across the NEM is highest in this scenario.

The model was used to compute a least-cost investment and dispatch generation development plan without PEC Stage 1 and with PEC Stage 1 as well as with two different PEC Stage 2 augmentation timing options across the three aforementioned scenarios. The two options assessed were:

- PEC 2 staged 26-27: staged commissioning of PEC Stage 2 between 1 Jul 2026 and 1 Jul 2027.
- PEC 2 staged 27-28: staged commissioning of PEC Stage 2 between 1 Jul 2027 and 1 Jul 2028.

The forecast gross market benefits of each PEC case must be compared to the relevant estimated cost of the PEC case to determine the forecast net market benefit. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by Transgrid outside of this Report using the forecast gross market benefits from this Report and other inputs.

An alternative counterfactual case without PEC Stage 1 or 2 was also modelled at Transgrid's request. As PEC Stage 1 has been built, the No PEC 1 case is a purely theoretical network state that is used to estimate gross total benefits of both stages of PEC to compare against total estimated project cost, including sunk costs.

To compute the least-cost solution with and without PEC, EY's Time Sequential Integrated Resource Planner (TSIRP) model was used. TSIRP makes decisions for each hourly dispatch interval (two-hourly for Green Energy Exports) in relation to:

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

[6] AEMO, 30 June 2022, 2022 *ISP Input assumptions and scenarios workbook v3.4*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en. Accessed 18 December 2024.

[7] Australian Government Department of Climate Change, Energy, the Environment and Water, 16 June 2022, *Australia submits new emissions target to UNFCCC*. Available at: https://www.dcceew.gov.au/about/news/australia-submits-new-emissions-target-to-unfccc. Accessed 17 January 2025.

The interval-to-interval decisions consider certain assumed operational constraints that include:

- Supply must equal demand in all dispatch intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR),
- Minimum loads for coal generators and CCGTs,
- Interconnector flow limits (between regions) and intra-regional transmission network flow limits with a focus on the southern New South Wales region,
- Maximum and minimum storage (conventional storage hydro, PHES, virtual power plant (VPP) and large-scale battery) reservoir limits and cyclic efficiency,
- New entrant capacity build limits for wind and solar for each REZ where applicable, and PHES in each region,
- Carbon budget constraints, and
- Renewable energy targets where applicable by region or NEM-wide,
- System security constraints in South Australia without PEC Stage 2.

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 captured in the modelling include:

- Capital costs of new generation and storage capacity installed (capex),
- Total fixed operation and maintenance (FOM) costs of all generation and storage capacity,
- Total VOM costs of all generation and storage capacity,
- Total fuel costs of all generation capacity,
- Total cost of voluntary demand-side participation (DSP) and USE,
- Transmission expansion costs associated with REZ development,
- Emissions as a byproduct of thermal generation valued according to AER's *Valuing emissions reduction* document[8], calculated as a post-process to the optimisation.

The forecast gross market benefits capture the impact of potential transmission losses to the extent that losses across interconnectors affect the generation that needs to be dispatched in each dispatch interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale batteries.

For each simulation, we computed the sum of these cost components and compared the difference between cases that included stages of the PEC upgrades and cases that did not include stages of the PEC upgrades (two counterfactual or base cases were considered) across the 25-year period (the Modelling Period), from 2025-26 to 2049-50. The difference in the calculated present value of costs is the forecast gross market benefits due to the PEC upgrades. Benefits presented are discounted to 30 June 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the 2024 AEMO ISP[2].

Table 1 shows forecast incremental gross market benefits of PEC Stage 2 which is calculated as the difference in system cost between a case that includes the full PEC upgrades (Stages 1 and 2) and a case that includes only the PEC Stage 1 upgrades. Table 2 shows the forecast total gross market benefits of the entire PEC project which is calculated as the difference in system cost between a case that includes the full PEC upgrades (Stages 1 and 2) and a theoretical case which does not include any of the PEC upgrades.

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[8] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 25 October 2024.

Table 1: Overview of forecast incremental gross market benefits for PEC Stage 2 across three scenarios discounted to 30 June 2023 in millions of real June 2023 dollar terms

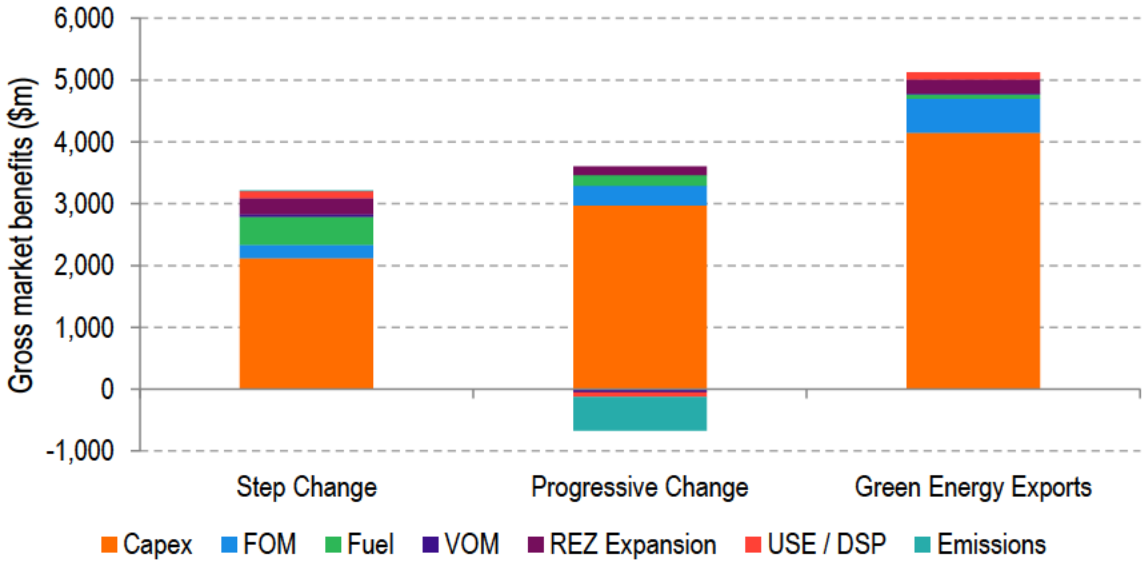
PEC option	PEC option timing	Forecast incremental gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 26-27	Staged timing from 1 Jul 2026 - 1 Jul 2027	3,214	2,942	5,126
PEC 2 staged 27-28	Staged timing from 1 2027 - 1 Jul 2028	3,051	2,713	4,631

Table 2: Overview of forecast total gross market benefits of PEC across three scenarios discounted to 30 June 2023 in millions of real June 2023 dollar terms

PEC option	PEC option timing	Forecast total gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 26-27	Staged timing from 1 Jul 2026 - 1 Jul 2027	3,906	3,682	6,504
PEC 2 staged 27-28	Staged timing from 1 2027 - 1 Jul 2028	3,742	3,452	6,009

In all scenarios, the forecast benefits of the PEC upgrades are primarily driven by capex savings across the NEM, followed by fuel and VOM cost savings as the second highest source of forecast benefit, as displayed in Figure 1 for PEC 2 staged 26-27. Forecast benefits for PEC 2 staged 27-28 have a similar composition of market benefits.

Figure 1: Composition of forecast incremental gross market benefits of PEC 2 staged 26-27 across scenarios; discounted to 30 June 2023 in millions of real June 2023 dollar terms



The forecast capex benefits associated with PEC Stage 2 are predominantly driven by supporting more cost-efficient investment in renewables to meet emissions abatement and renewable energy policies, including the federal 82% renewable energy by 2029-30 target and CIS renewable capacity target[1]. The fast pace of transition to renewable energy across all scenarios allows PEC Stage 2 to be highly utilised by improving interconnection of South Australia to New South Wales and the rest of the NEM, which includes improving connections between SWNSW and HumeLink within southern New South Wales. The improved interconnection to South Australia allows for better access to the higher resource potential wind resources in South Australia and thus more efficient utilisation of resources across the NEM.

There are also forecast fuel cost savings across all scenarios. This is due to higher fuel costs in the cases without PEC Stage 2 as a result of the South Australia system security constraints. These are a set of constraints imposed in the absence of PEC Stage 2 that limit dispatch of non-synchronous generation in South Australia to 2,500 MW and also constrain on a minimum number of gas units in South Australia. By alleviating these constraints, PEC Stage 2 reduces thermal dispatch and associated fuel costs in South Australia.

A secondary impact of the alleviation of these system security constraints with PEC Stage 2 is that emissions are also avoided which are then forecast to be spent elsewhere in the NEM on increased coal-fired generation in the near-term which allows renewable and storage capex to be deferred, while still meeting renewable energy and carbon budget targets.

PEC Stage 2 is forecast to have lower gross market benefits in the Progressive Change scenario compared to the Step Change scenario. This scenario forecasts the slowest transition to renewables of the three scenarios (although assumed coal-fired generator retirements are still accelerated relative to the announced retirement dates and are similar to the Step Change scenario assumptions to 2030). While forecast gross benefits are lower, the reductions in capex and FOM costs are higher than in the Step Change scenario. This is due to the Progressive Change scenario assuming significant demand reductions in the late 2020s across New South Wales, Victoria, Queensland and Tasmania, and the interaction of this demand outlook with the assumed renewable energy targets, which are the same across scenarios. With the assumed demand reductions and fixed coal closure dates, a significant percentage of annual energy to 2030 and 2035 is met with coal-fired generators and CCGTs operating at minimum load. There is then little headroom for increased coal or gas operation at times of low availability of wind and solar to meet demand while staying within the 82% renewable energy target. To meet expected demand while satisfying the 82% target without PEC Stage 2, some renewables are installed even though they are not frequently dispatched. This adds to benefits when some of this investment is avoided with PEC Stage 2.

Of the three scenarios modelled, PEC Stage 2 is forecast to have the highest gross market benefits in the Green Energy Exports scenario. As per the 2024 ISP assumptions[1], electricity consumption in the NEM is assumed to increase significantly over the Modelling Period in this scenario, predominately due to an increase in electricity demand for hydrogen production. By the early 2030s, the assumed demand in the NEM is four-fold higher than the current annual consumption. Due to the large amount of new capacity required to meet this assumed demand and more stringent carbon budget than the other scenarios, more new renewables and storage are required. The faster transition to renewable energy and storage leads to a greater opportunity for PEC to be utilised and reduce investment in renewable generators, storage and gas-fired generation.

2. Introduction

Transgrid engaged EY to undertake market modelling of system costs to forecast the gross market benefits to the NEM of additional transfer capacity between South Australia, New South Wales and Victoria with PEC. The proposed network augmentations comprise of a new 330 kV interconnector between New South Wales and South Australia. The interconnector runs from Robertstown in South Australia to Wagga Wagga in New South Wales, via the northernmost section of the transmission network in Victoria. It traverses between east and west, linking the REZs of Riverland, Murray River, and South-West New South Wales, providing additional transmission connection capacity to these REZs.

PEC is to be completed in two stages. Stage 1 comprises an initial 275 kV connection between Robertstown and a new substation at Bundey and a 330 kV connection between Bundey and Buronga, which is expected to release 150 MW of transfer capacity between New South Wales and South Australia. Stage 1 is currently undergoing inter-network testing. Stage 2 comprises a 330 kV connection between Buronga and a new switching station at Dinawan, a 500 kV connection between Dinawan and Wagga Wagga operated at 330 kV until VNI West is complete and a 220 kV line between Buronga and Red Cliffs, and is expected to release the full 800 MW of transfer capacity between New South Wales and South Australia (650 MW incremental to Stage 1).

This report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. EY computed the least-cost generation dispatch and capacity development plan for the NEM for three scenarios: Step Change, Progressive Change and Green Energy Exports. These scenarios combine input assumptions on policies, costs and generator technical parameters, as well as demand projections from AEMO in the 2024 IASR[9] as input to the 2024 ISP and assumed timing of major transmission upgrades and coal-fired generator retirement dates based on the 2024 ISP outcomes of the Optimal Development Path (ODP)[10]. Updates were included to reflect new market information from the AEMO Generation Information data as of July 2024[11] and transmission project proponents advised earliest in-service date where this was later than AEMO's ODP outcome[12]. The modelling methodology follows the CBA guidelines for actionable ISP projects published by the Australian Energy Regulator[13].

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:

- Capex of new generation and storage capacity installed,
- Total FOM costs of all generation and storage capacity,
- Total VOM costs of all generation and storage capacity,
- Total fuel costs of all generation capacity,
- Total cost of voluntary (demand-side participations, DSP) and involuntary load curtailment (USE),
- Transmission expansion costs associated with REZ development,

[9] AEMO, July 2024, *2024 ISP Inputs and Assumptions Workbook v6.0*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-isp-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 24 October 2024.
[10] AEMO, 26 June 2024, *2024 ISP*. Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 24 October 2024.
[11] AEMO, 29 July 2024, *NEM Generation Information July 2024*. *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 24 October 2024.
[12] AEMO, June 2024, *ISP Appendix 5. Network Investments*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en. Accessed 24 October 2024.
[13] Australian Energy Regulator, 6 October 2023, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/reviews/review-cost-benefit-analysis-and-regulatory-investment-test-guidelines. Accessed 24 October 2024.

- Transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model,
- Cost of emissions as a byproduct of thermal generation, valued according to AER's *Valuing emissions reduction* document[14] as a post-process to the optimisation.

Each category of gross market benefits is computed across the 25-year Modelling Period, from 2025-26 to 2049-50. Benefits presented are discounted to 30 June 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the 2024 IASR.

This modelling considers two different entry dates of PEC Stage 2, of which both options have their capacity released in two-monthly staged increments across the financial year based on inter-network testing hold point release. PEC 2 staged 26-27 assumes hold point release in two-month increments across the 2026-27 financial year with full capacity released by July 2027. PEC 2 staged 27-28 presents a delayed scenario and assumes hold point release across the 2027-28 financial year with full capacity released by July 2028.

Two alternative counterfactual cases without stages of the PEC upgrades are modelled to forecast:

- The incremental benefits of PEC Stage 2 at either timing relative to PEC Stage 1 only (PEC 1 case), and
- Total benefits of PEC Stage 2 relative to no PEC Stage 1 or 2 (No PEC 1 case).

The forecast gross market benefits of each PEC case must be compared to the relevant cost of the PEC case to determine the forecast net market benefit. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by Transgrid outside of this Report using the forecast gross market benefits from this Report and other inputs.

The alternative counterfactual case without Stage 1 or 2 of PEC was also modelled at Transgrid's request. As PEC Stage 1 has been built, the No PEC 1 case is a purely theoretical network state that is used to estimate gross total benefits of both stages of PEC to compare against total project cost, including sunk costs.

The Report is structured as follows:

- Section 3 describes the input assumptions and scenarios modelled.
- Section 4 presents the NEM capacity and generation outlook for the PEC Stage 1 case without PEC Stage 2 for the three scenarios.
- Section 5 presents the forecast incremental gross market benefits associated with PEC Stage 2. It is focussed on identifying and explaining the key sources of forecast gross market benefits for PEC Stage 2 compared to a system with PEC Stage 1 only.
- Section 6 presents the forecast total gross market benefits associated with PEC Stage 2 compared to a theoretical case without PEC Stage 1.
- 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 and transmission losses.
- Appendix C outlines model design and input data related to demand.
- Appendix D provides an overview of model inputs and methodologies related to supply of energy.

[14] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 25 October 2024

- Appendix E provides additional detail on the South Australia system security constraints identified by Transgrid to model system security requirements in South Australia without PEC Stage 2.
- Appendix F shows flow duration curves for interconnectors to South Australian (PEC, Heywood and Murraylink) in the Step Change scenario.
- Appendix G shows the glossary of all abbreviations referenced within this report.

3. Scenario assumptions

3.1 Overview of input assumptions

PEC gross market benefits have been assessed under the Step Change, Progressive Change and Green Energy Exports scenarios as chosen by Transgrid. The modelling combines input assumptions on policies, costs, generator technical parameters and demand projections from the AEMO 2024 IASR[9] as input to the 2024 ISP and assumed timing of major transmission upgrades and coal-fired generator retirement dates based on the 2024 ISP outcomes of the ODP[10]. Where transmission investment timing in the ODP was earlier than the earliest in-service date advised by the project proponent, Transgrid elected to adopt the later date. A more comprehensive list of assumptions and their sources is summarised in Table 3. All input assumptions were selected by Transgrid in accordance with the CBA guidelines.[13]

Table 3: Overview of key input parameters selected by Transgrid in the Step Change, Progressive Change and Green Energy Exports scenarios

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Underlying consumption	2023 Electricity Statement of Opportunities (ESOO)[15] - Step Change	2023 ESOO[15] - Progressive Change	2023 ESOO[15] - Green Energy Exports
Committed and anticipated generation	Committed and anticipated generators from AEMO's Generation Information July 2024[11]		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2024 IASR Assumptions Workbook[9] - Step Change	2024 IASR Assumptions Workbook[9] - Progressive Change	2024 IASR Assumptions Workbook[9] - Green Energy Exports
New entrant optional build earliest date	1 July 2025[16]		
Retirements of coal-fired power stations	2024 ISP Results Workbook[17] - Step Change ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024[11].	2024 ISP Results Workbook[17] - Progressive Change ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024[11].	2024 ISP Results Workbook[17] - Green Energy Exports ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024[11].

[15] AEMO, *Electricity Forecasting Data Portal*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 October 2024.

[16] The earliest date for optional new entrant build was initially selected as 1 Jul 2027 to reflect realistic lead times for new projects, noting this doesn't account for announced generator and storage projects that do not meet the committed or anticipated categories but are part-way through the lead time. However, the Green Energy Exports scenario was unable to achieve a realistic solution due to the large increase in demand between 1 Jul 2025 and 1 Jul 2027 resulting in very large gross benefits for PEC due to solutions requiring large amount of DSP dispatch to meet demand early in the Modelling Period. In response to these two factors, an earliest date for new entrant build was selected as 1 Jul 2025 by Transgrid.

[17] AEMO, June 2024, *2024 ISP Generation and storage outlook*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/supporting-materials/2024-isp-generation-and-storage-outlook.zip?la=en. Accessed 25 October 2024.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Retirements of other thermal units	Generator retirement dates from AEMO's Generation Information July 2024[11, 18]		
Gas fuel price	2024 IASR Workbook[9] - Step Change	2024 IASR Workbook[9] - Progressive Change	2024 IASR Workbook[9] - Green Energy Exports
Coal fuel price	2024 IASR Workbook[9] - Step Change	2024 IASR Workbook[9] - Progressive Change	2024 IASR Workbook[9] - Green Energy Exports
NEM carbon budget to achieve Federal Government's 2030 emissions reduction target	Budget for 2025-26 to 2029-30 derived from assumptions in 2024 IASR Workbook[9] and 204 ISP outcomes[17].[19]		
	528.1 Mt CO_2-e	523.2 Mt CO_2-e	540 Mt CO_2-e
NEM carbon budget to achieve 2050 temperature-linked emissions levels	Budget for 2025-26 to 2049-50 derived from 2024 ISP outcomes for each scenario[17].[20]		
	555 Mt CO_2-e	786 Mt CO_2-e	265 Mt CO_2-e
Federal Government Renewable Energy Target	2024 IASR Workbook[9]: 82% share of renewable generation by 2029-30		
Capacity Investment Scheme (CIS) renewable capacity target	2024 IASR Workbook[9]: 18,400 MW CIS eligible capacity by 2029-30, where CIS eligible renewables include new solar PV, onshore wind, and offshore wind in the NEM.		
Capacity Investment Scheme (CIS) - Clean dispatchable capacity target	2024 IASR Workbook[9]: 6,125 MW CIS clean dispatchable capacity by 2029-30, where CIS clean dispatchable capacity includes new concentrated solar thermal, pumped hydro, battery, hydrogen reciprocating engines and biomass.		
Victorian Government targets	2024 IASR Workbook[9]: ▪ Victoria Renewable Energy Target (VRET): 40% by 2025, 65% by 2030 and 95% by 2035 renewable generation as a percentage of Victorian generation. ▪ Victoria Energy Storage Target: 2.6 GW by 2030 and 6.3 GW by 2035 ▪ Victoria Offshore Wind Target: 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.[9]		
Queensland Renewable Energy Target (QRET)	2024 IASR Workbook[9]: ▪ 50% by 2029-30 ▪ 70% by 2031-32 ▪ 80% by 2034-35 renewable generation as a percentage of total Queensland demand.		
Tasmanian Renewable Energy Target (TRET)	2024 IASR Workbook[9]: 15,750 GWh by 2030 and 21,000 GWh by 2040, inclusive of spill		
NSW Electricity Infrastructure Roadmap	2024 IASR Workbook[9]: ▪ 5,547 TWh of eligible renewable generation in 2024-25 increasing to 33.6 TWh renewable generation in 2029-30 ▪ 2 GW of long duration storage (8 hrs or more) by 2029-30.		

[18] As per July 2024 generation information both Snuggery and Port Lincoln have been mothballed (announced withdrawal) from 1 July 2024 ahead of their expected closure year of 2028, however, the Final ISP does not capture this and neither does the modelling in this Report. There has also been a recent rule change request from the South Australian Government that proposes to take the units off mothball and allow them to dispatch at full capacity.
AEMC, November 2024, *South Australian jurisdictional derogation – Interim reliability reserve eligibility*. Available at: https://www.aemc.gov.au/rule-changes/south-australian-jurisdictional-derogation-interim-reliability-reserve-eligibility. Accessed 2 December 2024.
[19] The 2024 ISP Inputs and Assumptions workbook assumes 630 Mt CO_2-e from 2024-25 to 2029-30. We subtract the emissions for 2024-25 based on the ISP outcomes for each scenario to account for Modelling Period starting in 2025-26.
[20] The emissions budget for 2025-26 to 2049-50 derived from calculating the cumulative emissions outcomes provided in the 2024 ISP Results Workbook within the Modelling Period from 2025-26 to 2049-50.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
South Australia Hydrogen Jobs Plan	2024 IASR Workbook[9]: ▪ A 200 MW hydrogen-fuelled generator from 1 December 2025 ▪ A 250 MW electrolyser project included in the hydrogen production forecasts for each scenario		
Victorian SIPS	2024 IASR Workbook[9]: 150 MW import capability in VNI link after Victorian SIPS contract ends 31 March 2032		
Waratah Super Battery SIPS	2024 IASR Workbook[9]: 250 MW increase in export capacity from 1 July 2025 ending July 2030		
Project EnergyConnect	PEC release varies according to information in Table 4.		
Western Renewables Link	2024 IASR Workbook[9]: commissioned by 1 July 2027		
HumeLink	Commissioned by 1 December 2026 as earliest in-service date[12] on instructions from Transgrid		
New-England REZ Transmission	Earliest in-service date advised by proponent[12] ▪ New England REZ Infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome[17] – Step Change: ▪ New England Infrastructure Project Part 2 commissioned by July 2034	Earliest in-service date advised by proponent[12]: ▪ New England REZ Infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome[17] – Progressive Change: ▪ New England Infrastructure Project Part 2 commissioned by July 2041	Earliest in-service date advised by proponent[12]: ▪ New England REZ Infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome[17] – Green Energy Exports: ▪ New England Infrastructure Project Part 2 commissioned by July 2034
Central-West Orana REZ Transmission Link	2024 ISP outcome[17] – Step Change: commissioned by August 2028	2024 ISP outcome[17] – Progressive Change: commissioned by August 2028	2024 ISP outcome[17] – Green Energy Exports: commissioned by August 2028
Project Marinus Stage 1	Earliest in-service date advised by proponent[12]: commissioned by 1 December 2030		
Project Marinus Stage 2	2024 ISP outcome[17] – Step Change: commissioned by 1 July 2037	2024 ISP outcome[17] – Progressive Change: commissioned by 1 July 2036	Earliest in-service date advised by proponent[12]: commissioned by 1 December 2032
Queensland-New South Wales interconnector (QNI) Connect	2024 ISP outcome[17] – Step Change: commissioned by 1 July 2034	2024 ISP outcome[17] – Progressive Change: commissioned by 1 July 2034	2024 ISP outcome[17] – Green Energy Exports: commissioned by 1 July 2034
CopperString 2032	2024 ISP outcome[17]: commissioned by July 2029		
Victoria-New South Wales Interconnector (VNI) West	Earliest in-service date advised by proponent[12]: commissioned by 1 December 2029	2024 ISP outcome[17] – Progressive Change: commissioned by 1 July 2034	2024 ISP outcome[17] – Green Energy Exports: commissioned by 1 July 2030
Mid North South Australian REZ Expansion	2024 ISP outcome[17] – Step Change: Commissioned by 1 July 2029	2024 ISP outcome[17] – Progressive Change: commissioned by 1 July 2030	2024 ISP outcome[17] – Green Energy Exports: commissioned by 1 July 2029
Snowy 2.0	Generation Information July 2024[11]: Commissioned by December 2028		

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Discount rate	2024 IASR Workbook[9]: 7% real, pre-tax		
Modelling period	2025-26 to 2049-50		
Modelling temporal resolution (dispatch interval duration)	1 hour	1 hour	2 hour

3.2 Differences in assumptions with and without PEC Stage 2

The differences in the network model between the No PEC 1 case, PEC 1 and PEC 2 cases are shown in Table 4. The differences relate to the capacity of PEC and timing of the release of capacity. These parameters and timings have been advised by Transgrid.

Table 4: Modelled transmission capacity differences between cases

Link	Parameter timings and limits			
	No PEC 1	PEC 1	PEC 2 staged 26-27	PEC 2 staged 27-28
SA-SWNSW limit (both directions)	0 MW	With PEC Stage 1, 1 Jul 2025: 150 MW	With PEC Stage 1, 1 Jul 2025: 150 MW 1 Sep 2026, Hold Point 1: 250 MW 1 Nov 2026, Hold Point 2: 350 MW 1 Jan 2027, Hold Point 3: 450 MW 1 Mar 2027, Hold Point 4: 600 MW 1 May 2027, Hold Point 5: 750 MW 1 Jul 2027, Hold Point 6: 800 MW	With PEC Stage 1, 1 Jul 2025: 150 MW 1 Sep 2027, Hold Point 1: 250 MW 1 Nov 2027, Hold Point 2: 350 MW 1 Jan 2028, Hold Point 3: 450 MW 1 Mar 2028, Hold Point 4: 600 MW 1 May 2028, Hold Point 5: 750 MW 1 Jul 2028, Hold Point 6: 800 MW
SA-VIC (Heywood) limit	-550 MW / +600 MW	With PEC Stage 1, 1 Jul 2025: 650 MW both directions	With PEC Stage 1, 1 Jul 2025: 650 MW both directions With PEC Stage 2: unchanged	
SWNSW-SA & VIC-SA (Heywood) combined limit	-550 MW / +600 MW	With PEC Stage 1, 1 Jul 2025: -700 MW/ +750 MW	With PEC Stage 1, 1 Jul 2025: -700 MW/ 750 MW 1 Sep 2026, Hold Point 1: -815 MW/ +835 MW 1 Nov2026, Hold Point 2: -931 MW/ +919 MW/ 1 Jan 2027, Hold Point 3: -1,046 MW/ +1,004 MW 1 Mar 2027, Hold Point 4: -1,219 MW/ +1,131 MW 1 May 2027, Hold Point 5: -1,335 MW/ +1,215 MW 1 Jul 2027, Hold Point 6: -1,450 MW/ +1,300 MW	With PEC Stage 1, 1 Jul 2025: -700 MW/ +750 MW 1 Sep 2027, Hold Point 1: -815 MW/ +835 MW 1 Nov 2027, Hold Point 2: -931 MW/ +919 MW 1 Jan 2028, Hold Point 3: -1,046 MW/ +1,004 MW 1 Mar 2028, Hold Point 4: -1,219 MW/ +1,131 MW 1 May 2028, Hold Point 5: -1,335 MW/ +1,215 MW 1 Jul 2028, Hold Point 6: -1,450 MW/ +1,300 MW

Link	Parameter timings and limits			
	No PEC 1	PEC 1	PEC 2 staged 26-27	PEC 2 staged 27-28
SWNSW-Wagga	-700 MW/ +500 MW (unchanged with PEC Stage 1) After HumeLink, 1 Dec 2026 no change After VNI West (scenario-dependent): -2,500 MW/ 2,700 MW		-700 MW/ +500 MW (unchanged with PEC Stage 1) 1 Sep 2026, Hold Point 1: -885 MW/746 MW 1 Nov 2026, Hold Point 2: -1,069 MW/ 992 MW After HumeLink, 1 Dec 2026: no change 1 Jan 2027, Hold Point 3: -1,254 MW/ 1,238 MW 1 Mar 2027, Hold Point 4: -1,531 MW/ 1,608 MW 1 May 2027, Hold Point 5: -1,715 MW/1,854 MW 1 Jul 2027, Hold Point 6: -1,900 MW/ 2,100 MW After VNI West (scenario-dependent): -3,000 MW/ 2,700 MW	-700 MW/ +500 MW (unchanged with PEC Stage 1) After HumeLink, 1 Dec 2026: no change 1 Sep 2027, Hold Point 1: -885 MW/746 MW 1 Nov 2027, Hold Point 2: -1,069 MW/ 992 MW 1 Jan 2028, Hold Point 3: -1,254 MW/ 1,238 MW 1 Mar 2028, Hold Point 4: -1,531 MW/ 1,608 MW 1 May 2028, Hold Point 5: -1,715 MW/1,854 MW 1 Jul 2028, Hold Point 6: -1,900 MW/ 2,100 MW After VNI West (scenario-dependent): -3,000 MW/ 2,700 MW
Dispatch limit for existing generation in SWNSW REZ (N5), near Darlington Point (solar and BESS) and Broken Hill REZ (N4)[21]	940 MW	With PEC Stage 1, 1 Jul 2025: 940 MW (unchanged)	With PEC Stage 1, 1 Jul 2025: 940 MW (unchanged) With PEC Stage 2, 1 Jul 2027: 1,680 MW	With PEC Stage 1, 1 Jul 2025: 940 MW (unchanged) With PEC Stage 2, 1 Jul 2028: 1,680 MW
SWNSW (N5) REZ transmission modifier	215 MW After HumeLink, 1 Dec 2026: no change After VNI West (scenario-dependent): 2,015 MW (+1,800 MW)	After PEC Stage 1, 1 Jul 2025: 365 MW (+150 MW) After HumeLink, 1 Dec 2026: no change After VNI West (scenario-dependent): 2,165MW (+1,800 MW)	After PEC Stage 1, 1 Jul 2025: 365 MW (+150 MW) After HumeLink, 1 Dec 2026: no change After PEC Stage 2, 1 Jul 2027: 1,815 MW (+1,450 MW) After VNI West (scenario-dependent): 2,715 MW (+900 MW)	After PEC Stage 1, 1 Jul 2025: 365 MW (+150 MW) After HumeLink, 1 Dec 2026: no change After PEC Stage 2, 1 Jul 2028: 1,815 MW (+1,450 MW) After VNI West (scenario-dependent): 2,715 MW (+900 MW)

[21] The SWNSW1 group generation constraint considers the following units: Broken Hill Solar Farm, Silverton Wind Farm, Broken Hill BESS, Silver City BESS, Limondale SF 1, Limondale SF 2, Sunraysia SF, Limondale BESS, Coleambally SF, Finley SF, Hillston SF, Darlington Point SF, Darlington Point BESS, Riverina BESS 1, Riverina BESS 2. Total capacity behind the constraint is 1.86 GW: 1.21 GW solar, 200 MW wind, 450 MW BESS

Link	Parameter timings and limits			
	No PEC 1	PEC 1	PEC 2 staged 26-27	PEC 2 staged 27-28
Murray River (V2) REZ transmission modifier	440 MW summer/ 660 MW not summer After VNI West (scenario-dependent): 2,020 MW summer/ 2,220 MW not summer (+1,580 MW)	With PEC Stage 1, 1 Jul 2025: 440 MW summer/ 660 MW not summer (unchanged) After VNI West (scenario-dependent): 2,020 MW summer/ 2,220 MW not summer (+1,580 MW)	With PEC Stage 1, 1 Jul 2025: 440 MW summer/ 660 MW not summer (unchanged) After PEC Stage 2, 1 Jul 2027: 840 MW summer/1,040 MW not summer (+400 MW) After VNI West (scenario-dependent): 2,420 MW summer/2,620 MW not summer (+1,580 MW)	With PEC Stage 1, 1 Jul 2025: 440 MW summer/ 660 MW not summer (unchanged) After PEC Stage 2, 1 Jul 2028: 840 MW summer/1,040 MW not summer (+400 MW) After VNI West (scenario-dependent): 2,420 MW summer/2,620 MW not summer (+1,580 MW)
Riverland (S2) REZ transmission modifier	130 MW	With PEC Stage 1, 1 Jul 2025: 280 MW (+150 MW)	With PEC Stage 1, 1 Jul 2025: 280 MW (+150 MW) After PEC Stage 2, 1 Jul 2027: 930 MW (+650 MW)	With PEC Stage 1, 1 Jul 2025: 280 MW (+150 MW) After PEC Stage 2, 1 Jul 2028: 930 MW (+650 MW)

The presence of PEC was also assumed to affect the application of constraints to meet system security requirements in South Australia. These constraints were modelled as per AEMO's 'Transfer Limit Advice - System Strength in South Australia and Victoria[22] document, Table 1. Transgrid advised that constraints would apply in the absence of PEC Stage 2. Two different sets of constraints were applied - one constraining on South Australia gas units, and another limiting the dispatch of non-synchronous generators. The application of the constraints for different network states is summarised in Table 5 and explained further in the remainder of this section.

Table 5: Summary of modelled South Australia system security constraints with PEC Stage 2 and without PEC Stage 2

Scenario	South Australia gas constraint			South Australia non-synchronous generation constraint		
	No PEC	PEC 1	PEC 2	No PEC	PEC 1	PEC 2
Step Change	Disabled 1/7/2037		Disabled with PEC 2 entry	Enforced throughout modelling period		Disabled with PEC 2 entry
Progressive Change	Disabled 1/7/2037		Disabled with PEC 2 entry	Enforced throughout modelling period		Disabled with PEC 2 entry

[22] AEMO, April 2024, *Transfer Limit Advice - System Strength in SA and Victoria*, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf. Accessed 1 October 2024

Scenario	South Australia gas constraint			South Australia non-synchronous generation constraint		
	No PEC	PEC 1	PEC 2	No PEC	PEC 1	PEC 2
Green Energy Exports				Disabled as cannot achieve a feasible solution in this scenario. The 2,500 MW limit on dispatch of non-synchronous generators, results in large amounts of hydrogen turbine build to serve large amounts of hydrogen load demand in SA.		

The South Australia gas constraint was applied in the without PEC Stage 2 cases until 2037. After this date, diesel generators and peaking plants would be required to be constrained on which does not form a reasonable scenario[23]. The system security constraints are assumed to be alleviated with PEC Stage 2, as advised by Transgrid Table 5. Gas units in South Australia are modelled to retire on fixed dates according to the latest AEMO Generation Information document[11]. See Appendix E for more details on individual unit retirement date assumptions.

The selection of units constrained on to meet the South Australia gas constraint was based on analysis which determined the least-cost combination of units to constrain. The following constraints were formulated to meet the South Australia gas constraint and applied in each dispatch interval:

$$\begin{aligned}
&\textit{Barker Inlet Power Station} \geq 30\ MW\ (4\ \textit{units minimum load}) \\
&\textit{Pelican Point CCGT} \geq 60\ MW\ (1\ \textit{unit minimum load}) \\
&\textit{Osborne} \geq 60\ MW\ (1\ \textit{unit minimum load})\ \textit{if Pelican Point is unavailable}
\end{aligned}$$

A non-synchronous generation constraint was also applied as part of the requirements outlined in Table 1 of the above-mentioned document. This limited the dispatch of[22] all non-synchronous generation (large-scale solar, wind and storage) to less than 2,500 MW per dispatch interval in the absence of PEC Stage 2. In the Step Change and Progressive Change scenarios, this constraint was applied throughout the entire Modelling Period in the cases without PEC Stage 2 and was alleviated with PEC Stage 2, as advised by Transgrid. In the Green Energy Exports scenario, we did not apply this constraint, even in the absence of PEC Stage 2 as a feasible solution could not be calculated. This scenario assumes significant load growth in South Australia, largely due to hydrogen production load for export. With a limit on non-synchronous generation without PEC Stage 2, the only new synchronous generation options available to build to serve this load in the model were hydrogen turbines and gas turbines; but gas turbine generation is severely limited by the tight assumed hydrogen budget. It is not reasonable to build and dispatch significant quantities of hydrogen turbines to serve hydrogen load for export.

3.3 Differences to AEMO ISP input assumptions

There were several deviations from the ISP 2024 input assumptions (IASR v6.0[9]) and outcomes applied as input assumptions to this modelling. These capture greater network resolution in areas of interest and more up-to-date information regarding timing of committed and anticipated generation, storage and network investments. These differences are summarised in Table 6. These deviations were decided upon in consultation with Transgrid.

[23] From 2037 there may be more credible solutions to alleviate the South Australia gas constraint including building synchronous condensers or constraining on peaking plant. If the cost of such a solution was included in the base case it would result in higher benefits for PEC 2. Given this, and the uncertainty around the cost of a solution, Transgrid have opted for a conservative view on benefits which is to turn off the constraint from 2037.

Table 6: Summary of differences with AEMO ISP 2024 input assumption and outcomes

Key drivers input parameter	2024 ISP input assumptions[9] and outcomes[17] applied as input assumptions	EY modelling
Network model	Nodal model with some regions divided into subregions (nodes): ▪ 2 subregions in South Australia ▪ Southern NSW modelled as one node ▪ 4 subregions in Queensland See IASR Workbook 'Network representation tab' for detail.[9]	Greater detail in Southern New South Wales to capture differences in flow in area of greatest interest. Less detail in South Australia and Queensland to maintain tractability. Specifically: ▪ South Australia modelled as one node ▪ Southern New South Wales split into 8 nodes ▪ Queensland modelled as 1 node See Appendix B for more detail.
PEC Stage 2 commissioning	Full release of total capacity on 1 Jul 2027[9]	Staged release of capacity in two monthly increments from September 2026 fully released in July 2027 for PEC 2 staged 26-27 case and in increments from September 2027 fully released in July 2028 for PEC 2 staged 27-28 (delayed) case
HumeLink commissioning date	ISP outcomes[10] Step Change: 1 Jul 2029 Progressive Change: 1 Jul 2030 Green Energy Exports: 1 Jul 2029	All scenarios: 1 Dec 2026 as advised by Transgrid
Assumed network upgrades	Committed, anticipated, actionable and future ISP projects[12]	Committed, anticipated and actionable ISP projects
New entrant optional build earliest date (above and beyond committed and anticipated)	1 Jul 2024[12,17,24]	1 Jul 2025[16]
Dispatch limit for existing generation in SWNSW REZ (N5), near Darlington Point (solar and BESS) and Broken Hill REZ (N4)	940 MW transmission limit before and after PEC Stage 2 AEMO's SWNSW1 group transmission constraint limits dispatch of: Limondale SF, Limondale 2 SF, Sunraysia SF, Coleambally SF, Finley SF, Darlington Point SF, Hillston SF, Darlington Point BESS, Riverina BESS 1, Riverina BESS 2 Total maximum load capacity behind the constraint is 1.06 GW: 910 MW solar, 150 MW BESS	940 MW before PEC Stage 2 1,440 MW after PEC Stage 2 An alternate version of the dispatch constraint includes units in Broken Hill REZ, as advised by Transgrid. It limits the dispatch of the following units in addition to those in AEMO's SWNSW1 group: Broken Hill Solar Farm, Silverton Wind Farm, Broken Hill BESS, Silver City BESS, Limondale BESS. Total maximum load capacity behind the constraint is 1.86 GW: 1.21 GW solar, 200 MW wind, 450 MW BESS

[24] While the IASR workbook contains lead times for various technologies, these do not account for announced generator and storage projects that do not meet the committed or anticipated categories but are part-way through the lead time. The AEMO ISP outcomes show earliest generator capital expenditure in 2024-25 in the Green Energy Exports scenario, so we have inferred that optional build is allowed in the ISP modelling from this date.

Key drivers input parameter	2024 ISP input assumptions[9] and outcomes[17] applied as input assumptions	EY modelling
South-West NSW REZ transmission limit	In all scenarios, HumeLink is assumed to be commissioned after PEC Stage 2. Limit increases as follows: ▪ After PEC Stage 1: 365 MW ▪ After PEC Stage 2: 1,015 MW (+650 MW) ▪ After HumeLink: 1,815 MW (+800 MW) ▪ After VNI West: 2,715 MW (+900 MW) No modelling of cases without PEC Stage 2 (No PEC 1, PEC 1)	PEC Stage 2 is assumed to be commissioned after HumeLink in all scenarios; the uplift due to HumeLink is only realised after PEC Stage 2 is commissioned, as advised by Transgrid. ▪ After PEC Stage 1: 365 MW ▪ After HumeLink: 365 MW (no uplift) ▪ After PEC Stage 2: 1,815 MW (+1,450 MW) ▪ After VNI West: 2,715 MW (+900 MW) Without PEC Stage 2 (No PEC 1, PEC 1 cases), there are different uplifts applied as shown in Table 4.
South Australia system security constraints	The full PEC upgrades are committed in all scenarios and therefore the system security constraints are not considered, even for the modelled years prior to the assumed entry of PEC Stage 2.	Application of SA gas constraint and SA non-synchronous generation constraint to reflect system security requirements in scenarios without PEC Stage 2.

3.4 Controllability of PEC and loop flow constraint

PEC is modelled as a fully controllable link as described in Appendix B which approximates the controllability provided by the phase shifting transformers at Buronga that form part of the project.

The integration of PEC into the NEM will create the possibility of loop flows, including the potential for "spring washer effect" on local pricing nodes, counter-price flows between regions and negative inter-regional settlement residues to accrue. AEMO has identified potential options to manage these factors including a proposal to implement a loop flow constraint equation. [25] The details of potential loop flow constraints under various future network states are still uncertain and so these constraints have not been applied. Furthermore, the ISP does not consider a loop flow constraint in modelling PEC.

[25] AEMO, November 2023, *Project EnergyConnect Implementation – Directions Paper*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/pec-market-integration-paper/directions-paper-for-consultation/pec-market-integration---directions-paper-for-consultation.pdf?la=en. Accessed 25 October 2024

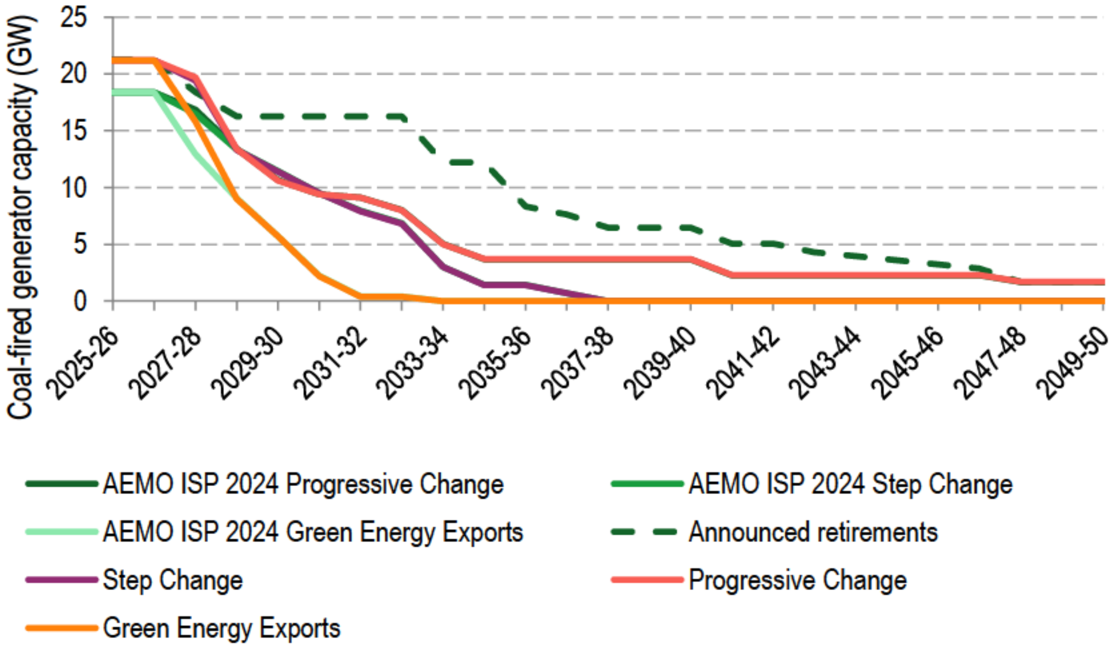
4. Forecast NEM capacity and generation outlook with PEC Stage 1 only

Before presenting the forecast benefits of the PEC options, it is useful to understand the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the counterfactual case with PEC Stage 1 only. We have modelled two alternative counterfactuals (PEC 1 and No PEC 1), but this section focusses on the PEC 1 case which assumes PEC Stage 1 only, given that the No PEC 1 case is a purely theoretical counterfactual.

4.1 Forecast coal-fired power plant withdrawal

Coal-fired generators are assumed to retire at the scenario-specific dates assessed by AEMO in their 2024 ISP[17], which are frequently in advance of announced retirement dates to meet assumed carbon budgets and renewable energy targets. Eraring is assumed to retire in Aug 2027 in all scenarios as announced[5], which is later than the assumption based on the 2024 ISP outcomes. The assumed capacity of coal-fired generation across the NEM is illustrated in Figure 2 alongside the latest announced retirements and the ISP 2024 outcomes.

Figure 2: Assumed coal-fired generator capacity in the NEM across all scenarios for all PEC cases



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, renewable energy targets (federal, CIS, NSW Electricity Infrastructure Roadmap, VRET, QRET and TRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. AEMO's ISP 2024 forecasts the entire coal capacity to withdraw by the early 2030s in the Green Energy Exports scenario. This is forecast by AEMO to be closer to 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast by AEMO to remain until just prior to the end of the modelling period.

4.2 Forecast capacity and generation outlook

The NEM-wide capacity mix forecast in the Step Change scenario without PEC Stage 2 is shown in Figure 3 and the corresponding generation mix in Figure 4. In this scenario, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large scale battery and PHES. This outcome is broadly consistent with the 2024 ISP outcomes for this scenario, noting the ISP does not model an equivalent network state with PEC Stage 1 only.

Figure 3: NEM capacity mix forecast for the Step Change scenario with PEC Stage 1 only

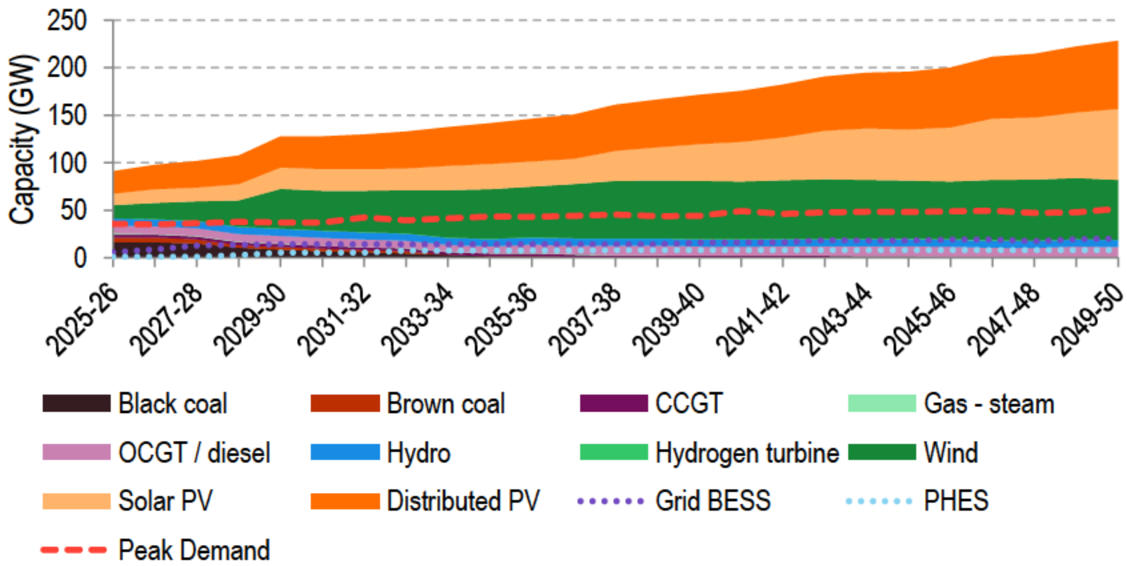
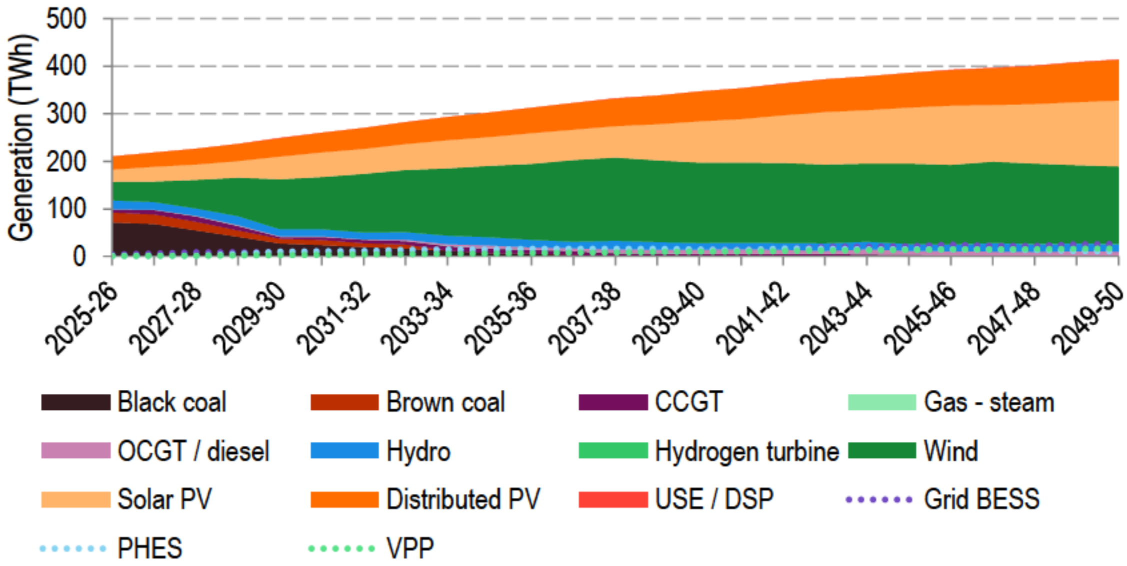


Figure 4: NEM generation mix forecast for the Step Change scenario with PEC Stage 1 only

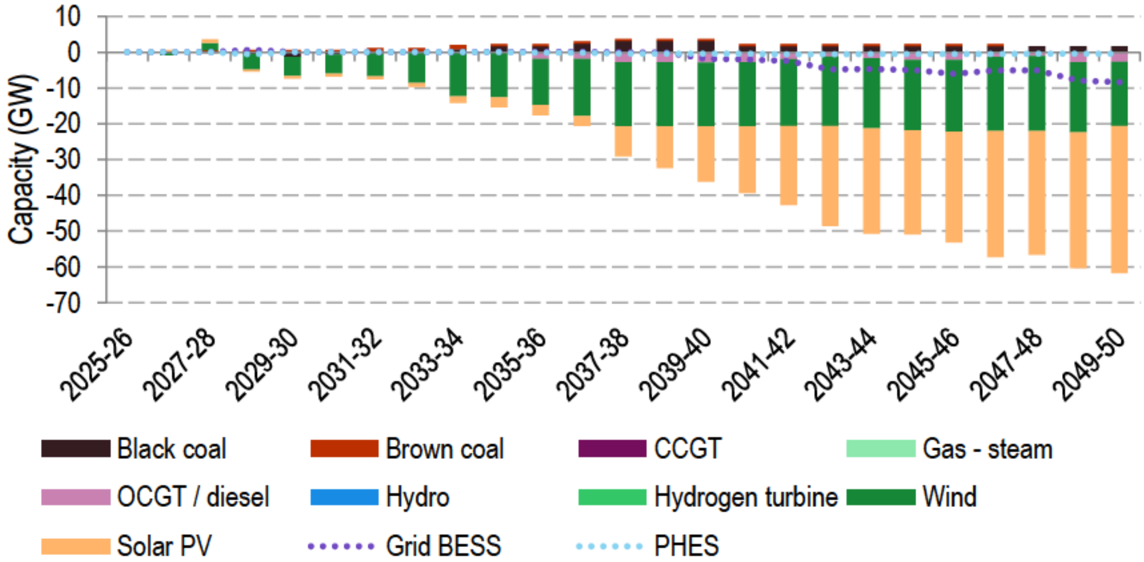


Up to 2030, new wind and solar build is largely driven by the NEM carbon budget to achieve the federal emissions reduction target. During this period, the federal renewable energy policy and CIS drives outcomes ahead of state-based renewable energy targets and entry of renewable capacity to replace coal retirements to achieve the assumed carbon budget. To replace the retiring capacity, wind capacity is predominantly forecast to be installed throughout the mid-to-late 2020s, along with large-scale BESS and PHES capacity in line with the assumed state-based storage targets. Snowy 2.0 (which is assumed to be committed in accordance with the 2024 ISP) also forms a significant part of the forecast PHES generation in 2028-29. Solar PV capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast new gas-fired capacity provides energy at times of low wind and solar availability (while respecting the assumed renewable energy targets and carbon budget) and supports reserve requirements. Overall, the NEM is forecast to have roughly 252 GW total generation capacity and storage by 2049-50, including distributed PV, which is an input assumption.

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 the other two scenarios relative to the Step Change scenario, while Figure 6 and Figure 8 show the difference in forecast generation. The differences are presented as alternative scenario minus the Step Change scenario (e.g. Figure 5 shows Progressive Change scenario capacity minus Step Change scenario capacity; a negative position indicates that the Progressive Change scenario has less forecast capacity than the Step Change scenario, and vice versa). Both capacity and generation differences for each scenario show similar trends.

Figure 5 and Figure 6 show that the Progressive Change scenario is assumed to have similar coal retirement dates to the Step Change scenario to 2030 but retains coal generation in the longer term and because of this forecast reduced installation of wind and solar capacity compared to the Step Change scenario. This is due to different assumptions such as the less restrictive carbon budget, lower demand outlook and other underlying input data, as defined by the 2024 ISP.

Figure 5: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios with PEC Stage 1 only[26]



[26] Note that *capacities* of distributed PV, behind-the-meter storage, VPPs and DSP are not shown as these are an input assumption, as is the generation of behind-the-meter storage. Distributed PV *generation* is shown to highlight the differences between scenarios despite being an input assumption. VPPs and DSP generation is explicitly modelled so is shown.

Figure 6: Difference in NEM generation forecast between the Progressive Change and Step Change scenarios with PEC Stage 1 only[26]

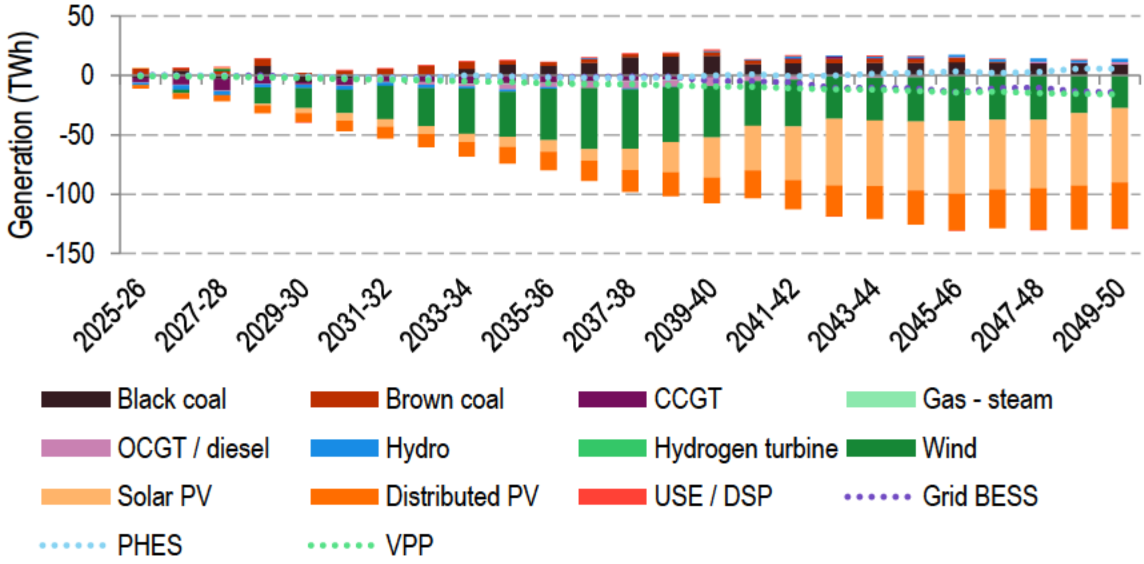


Figure 7 and Figure 8 show that Green Energy exports scenario is forecast to withdraw coal generation and install wind and solar generation more rapidly than the Step Change scenario due to different assumptions such as the more restrictive carbon budget and higher demand outlook, as defined by the 2024 ISP.

Figure 7: Difference in NEM capacity forecast between the Green Energy Exports and Step Change scenarios with PEC Stage 1 only[26]

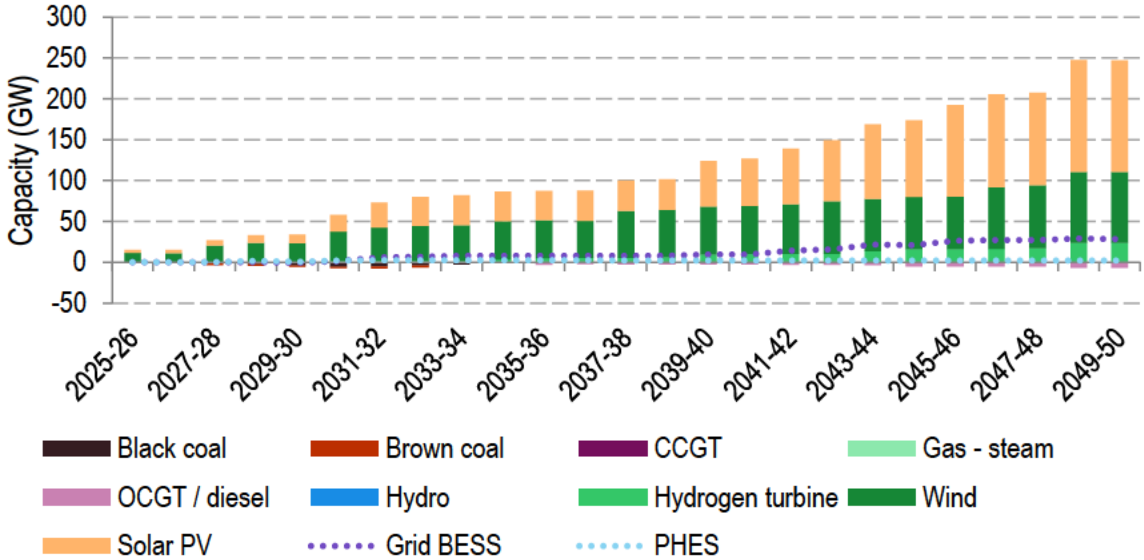
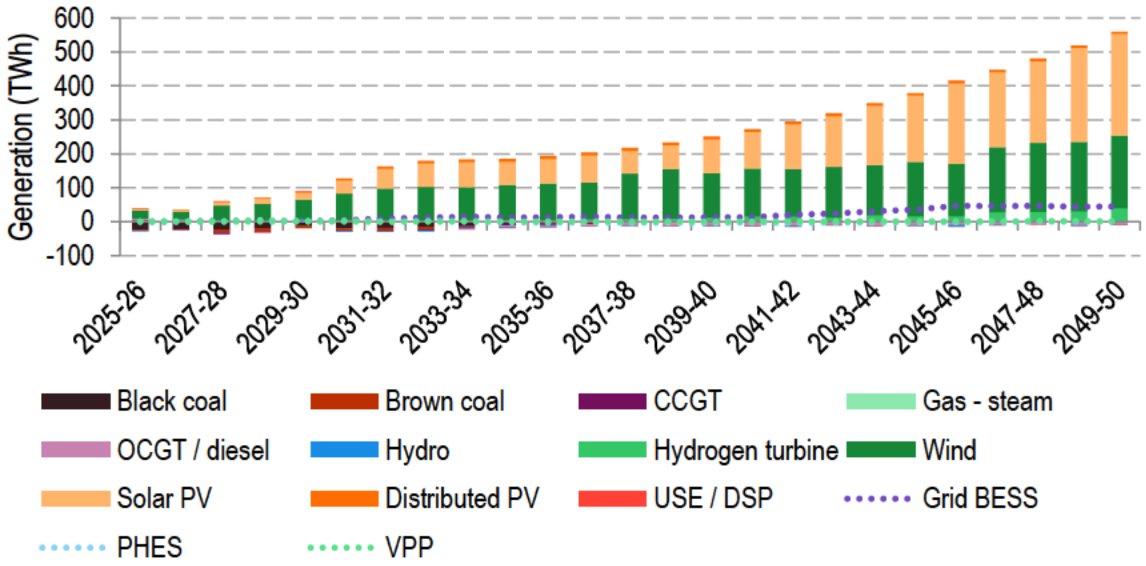


Figure 8: Difference in NEM generation forecast between the Green Energy Exports and Step Change scenarios with PEC Stage 1 only[26]



5. Forecast incremental gross market benefit outcomes

5.1 Summary of forecast incremental gross market benefit outcomes across scenarios

Table 7 shows the forecast gross market benefits of PEC Stage 2 over the 25-year Modelling Period from 2025-26 to 2049-50 for the Step Change, Progressive Change and Green Energy Exports scenarios compared to the case with PEC Stage 1 only. This is referred to as the incremental market benefits. The PEC 2 staged 26-27 case represents the staged commissioning of PEC Stage 2 between 1 July 2026 and 1 July 2027.

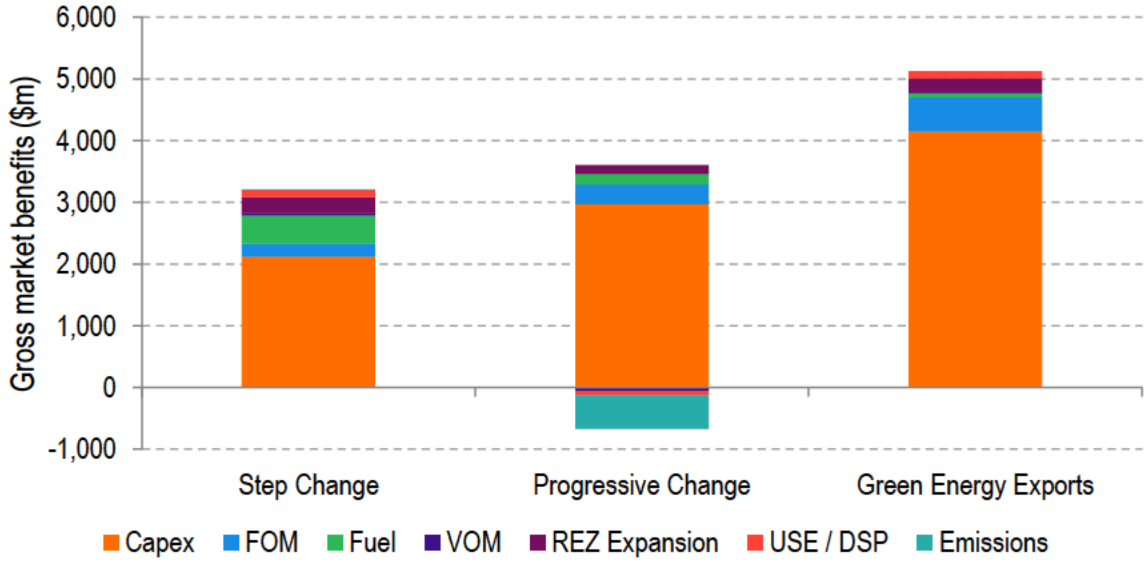
Table 7: Overview of forecast incremental gross market benefits for PEC Stage 2 (relative to PEC Stage 1 only) in all scenarios; discounted to 30 June 2023 in millions of real June 2023 dollar terms

PEC option	PEC option timing	Forecast incremental gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 26-27	Staged timing from 1/07/2026-1/07/2027	3,214	2,942	5,126

The forecast gross market benefit in each scenario must be compared to the estimated cost of PEC Stage 2 to determine the forecast net market benefit. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by Transgrid outside of this Report using forecast gross market benefits from this Report and other inputs.

Figure 9 displays the forecast benefits for PEC 2 staged 26-27. In all scenarios, the forecast benefits of PEC are primarily driven by capex saving across the NEM, followed by FOM savings for Progressive Change and Green Energy Exports and fuel savings for Step Change as the second highest source of forecast benefit. Benefits for a 12-month delay in commissioning of PEC Stage 2 have a similar composition of market benefits and are described in more detail in Section 5.5.

Figure 9: Composition of forecast incremental gross market benefits of PEC 2 staged 26-27 across scenarios (relative to PEC Stage 1 only); discounted to 30 June 2023 in millions of real June 2023 dollar terms



The forecast capex benefits associated with PEC Stage 2 are predominantly driven by supporting more cost-efficient investment in renewables to meet demand while respecting emissions abatement and renewable energy policies as per the 2024 ISP assumptions, including the federal renewable energy target of 82% by 2029-30 and CIS renewable target. The fast pace of the transition to renewable energy across all scenarios allows PEC Stage 2 to be highly utilised by improving interconnection of South Australia to New South Wales and the rest of the NEM, which includes improving connections between South-West New South Wales and HumeLink. The improved connections allow for better access to the higher resource potential wind resources in South Australia and thus more efficient utilisation of resources across the NEM, which generally reduces forecast investment in wind and solar in other regions.

There are also fuel cost savings across all scenarios. With PEC Stage 1 only, assumed system security constraints limit dispatch of wind, large-scale solar and BESS in South Australia and constrain on some South Australia gas units to run at a minimum load. The thermal generation has associated fuel costs. Alleviating these constraints with PEC Stage 2 reduces forecast fuel costs.

In the remainder of this section:

- Sections 5.2 to 5.4 describe the market dynamics for each of the three scenarios with PEC Stage 2 staged commissioning between 1 Jul 2026 and 1 Jul 2027.
- Section 5.5 outlines differences in forecast outcomes with the 12-month delay of PEC Stage 2 staged commissioning between 1 Jul 2027 and 1 Jul 2028.

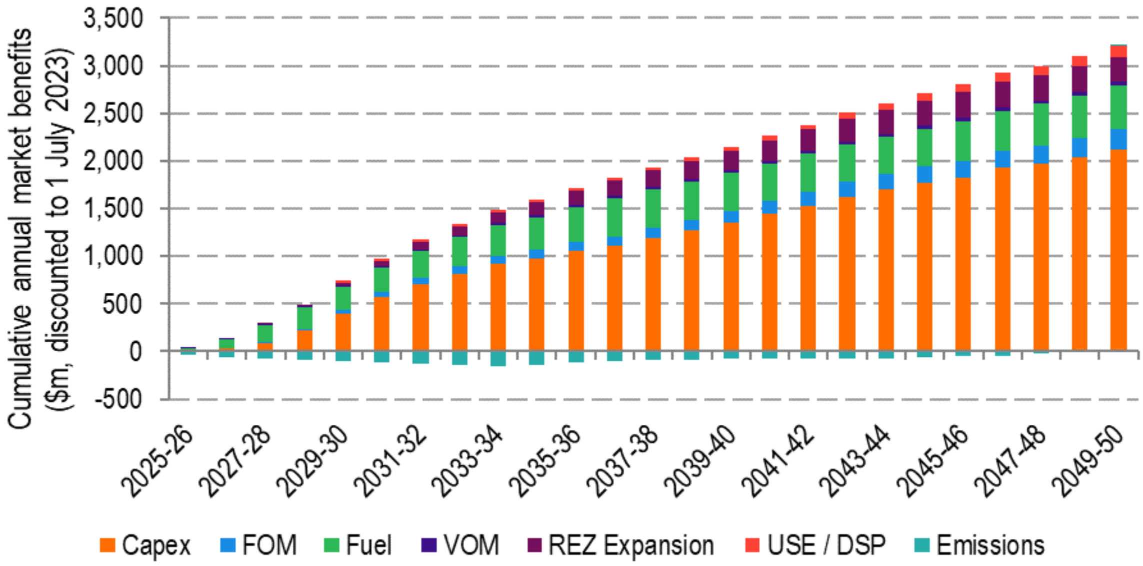
Overall forecast incremental benefits of PEC Stage 2 are highest in the Green Energy Exports scenario, followed by Step Change then Progressive Change. The relative magnitude of the different categories of benefits and the reasons for those differences are discussed in detail in Sections 5.2 to 5.4.

5.2 Market modelling outcomes for PEC 2 staged 26-27 Step Change scenario

5.2.1 Forecast gross market benefits, Step Change scenario

The gross market benefits forecast for PEC 2 staged 26-27 (staged commissioning between 1 Jul 2026 and 1 Jul 2027) in the Step Change scenario are shown in Figure 10 on an annual, discounted basis. Over the modelling period, the inclusion of PEC Stage 2 is forecast to result in $3,214m gross market benefits discounted to 30 June 2023 (in real June 2023 dollar terms).

Figure 10: Forecast cumulative gross market benefit of PEC 2 staged 26-27 relative to PEC 1 under the Step Change scenario; discounted to 30 June 2023 in millions of real June 2023 dollar terms



Market benefits due to PEC Stage 2 are predominantly forecast to occur after 2026-27 which is when PEC Stage 2 is modelled to begin staged commissioning. From 2028-29, capex benefits are accrued due to PEC Stage 2 providing greater accessibility to more cost-effective generation.

Most of the benefits of PEC Stage 2 are forecast to be from the reduction in expected capex costs, followed by savings from reduced fuel costs and REZ expansion costs.

5.2.2 Forecast NEM generation development plan, Step Change scenario

The differences in the forecast capacity and generation outlooks in the Step Change scenario with and without PEC Stage 2 are shown in Figure 11 and Figure 12, respectively.

Figure 11: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Step Change scenario, relative to PEC Stage 1

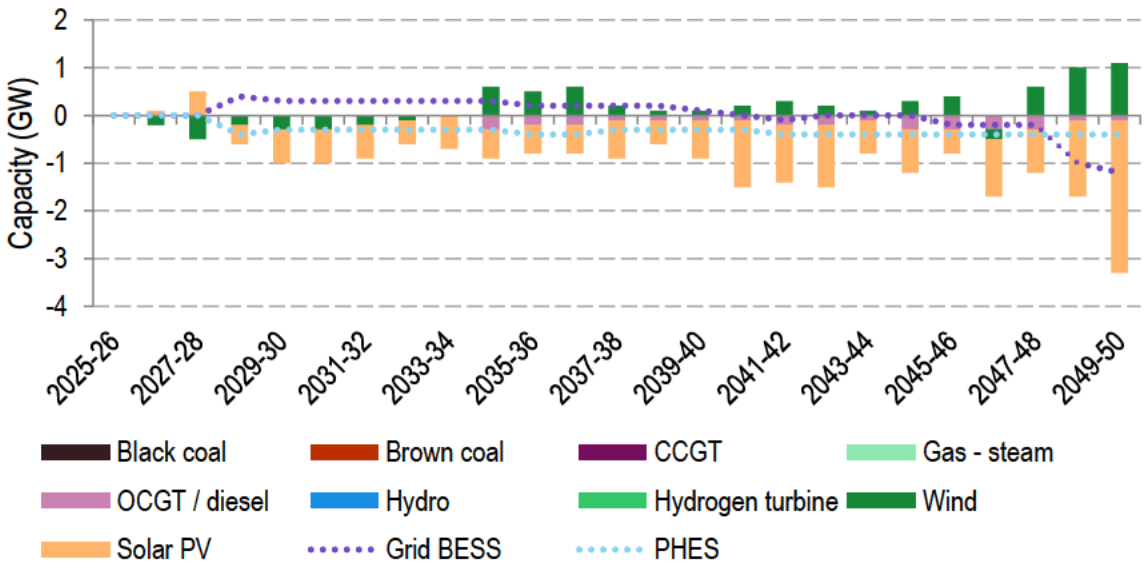
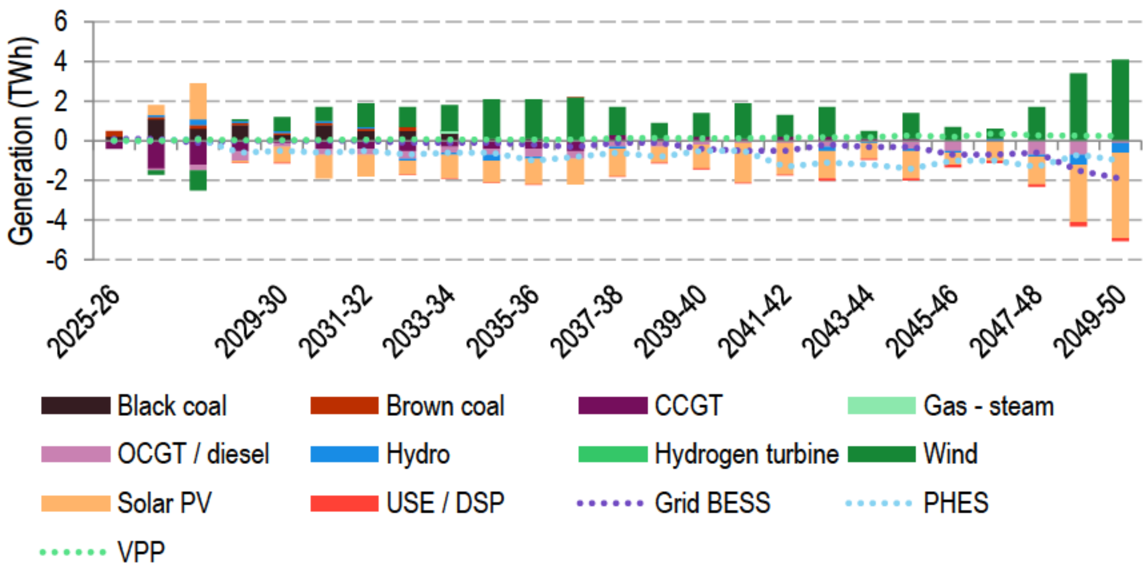


Figure 12: Forecast generation difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Step Change scenario, relative to PEC Stage 1

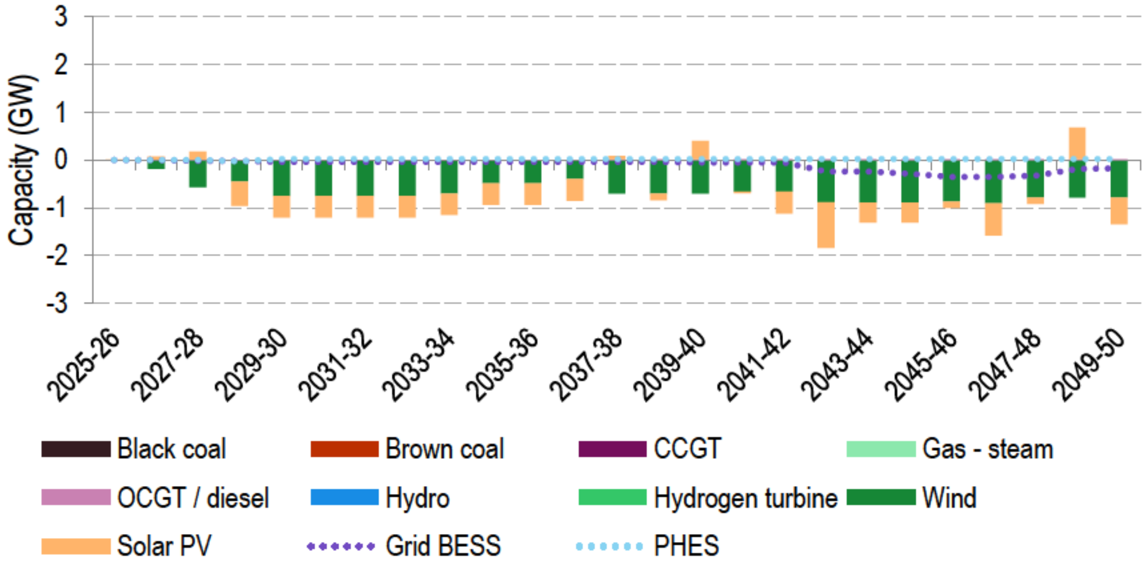


The forecast capacity difference in Figure 11 shows that in aggregate across the NEM solar, PHES and gas capacity are forecast to be reduced with PEC Stage 2 while wind capacity is forecast to increase. There are corresponding forecast capex and FOM savings as well as REZ expansion cost reductions due to lower transmission build to REZs with PEC Stage 2.

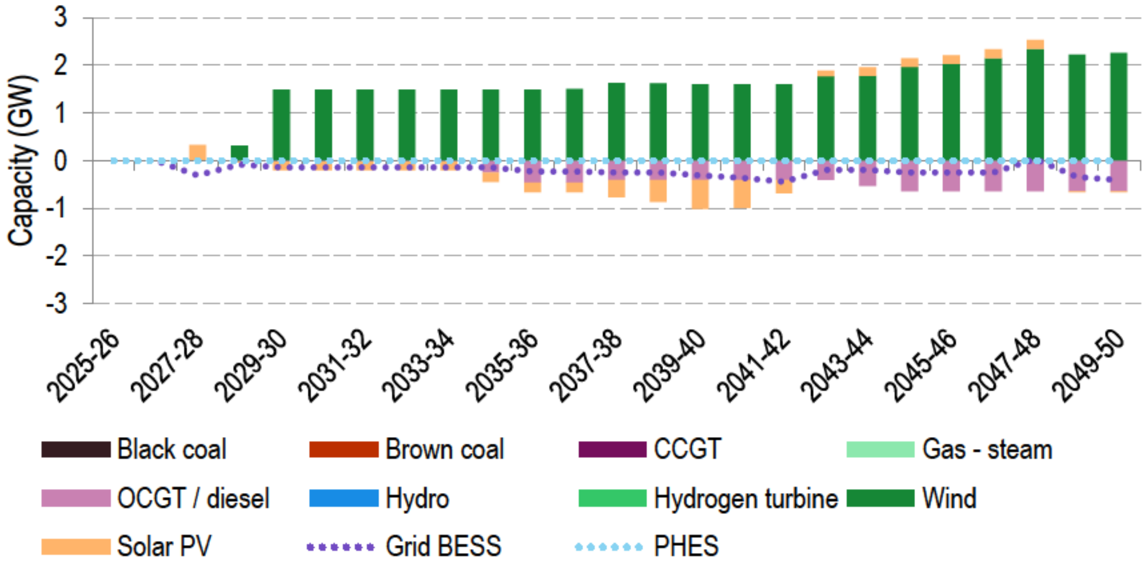
Figure 13 shows the difference in capacity with PEC Stage 2 for both New South Wales and South Australia. This breakdown shows that increased access to South Australia spurs on greater forecast investment in wind in the region, while there is decreased investment in New South Wales and Victoria. NEM-wide, from around 2039-40 the installation of large-scale BESS is also reduced. With greater interconnection, investment in storage overall reduces, and it becomes more efficient to build wind capacity than solar. Furthermore, discretionary build of OCGT units is reduced, primarily in South Australia, due to alleviation of the non-synchronous generation constraint with PEC Stage 2 allowing greater generation from renewables in South Australia.

Figure 13: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Step Change scenario, relative to PEC Stage 1

a. New South Wales



b. South Australia



The forecast generation difference in Figure 12 shows that forecast wind generation increases at a similar volume to the forecast reduction in solar generation, despite the replacement wind capacity being less than the avoided solar capacity as seen in Figure 11. This replacement wind capacity with

PEC Stage 2 is expected to achieve a higher capacity factor than the solar capacity in the PEC Stage 1 case, demonstrating increased efficiencies. The changes in forecast generation due to PEC Stage 2 generally align with the changes in capacity investment.

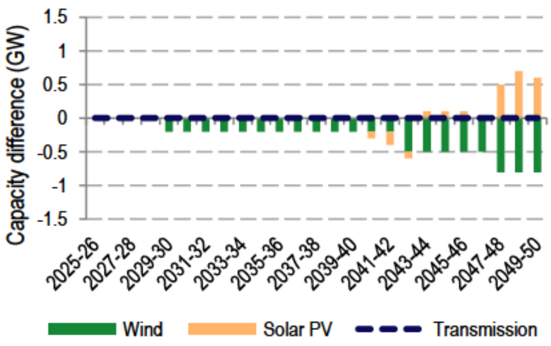
There is a 5.2 TWh increase in generation in South Australia with PEC Stage 2 relative to PEC Stage 1. The difference represents increased eastward flow on PEC, Heywood and Murraylink as well as decreased westward on Heywood and Murraylink into South Australia, partially offset by increased westward flow on PEC. Corresponding flow duration charts are shown in Appendix F. Of the 5.2 TWh difference in generation South Australia, 3.2 TWh represent net additional exports from South Australia (via PEC, Heywood and Murraylink) and 1.9 TWh serves South Australian demand.

With the inclusion of PEC Stage 2, there is a forecast decrease in OCGT and CCGT generation due to the removal of the South Australia system security constraints. The emissions savings due the reduction in South Australia gas generation allows for an increase in coal-fired generation while still meeting the assumed emissions budgets and renewable energy targets. Overall, PEC Stage 2 allows a lower cost system with increased generation from existing coal generators and deferral of renewable and storage capacity investment. This includes increased coal generation in Queensland and deferral of renewable build in Queensland with PEC Stage 2. The net impact of PEC Stage 2 on thermal generation is a forecast reduction in fuel costs.

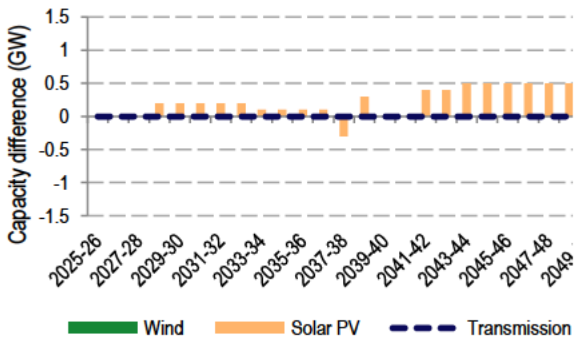
There are three REZs with transmission limits directly impacted by PEC Stage 2 (South-West New South Wales, Riverland, Murray River). Forecast capacity differences in these REZs with PEC Stage 2 are shown in Figure 14. While South-West NSW, Riverland and Murray River have assumed transmission limit increases with the commissioning of PEC Stage 2, it is not part of the least-cost development path to immediately build additional wind or solar to utilise this additional REZ transmission capacity. There is some increased investment forecast in Murray River and Riverland in the longer term. In South-West New South Wales REZ, forecast investment decreases overall with PEC Stage 2. Rather than new entrant build utilizing the increased capacity in these three REZs, PEC Stage 2 creates better connection to existing and committed capacity and as a result less investment is required to service demand and meet carbon budgets and renewable energy targets in the near-term. In the longer-term, it is anticipated that build of additional wind capacity in South Australia is lower cost than New South Wales; the improved connection through PEC Stage 2 to Sydney could be used to transport power from South Australia and offset build in New South Wales. The assumed average capacity factors for high/medium wind in South-West NSW REZ are 29%/29% compared to 37%/36% in Mid-North SA.

Figure 14: Forecast REZ capacity mix difference between PEC 2 staged 26-27 and PEC 1 case in the Step Change scenario

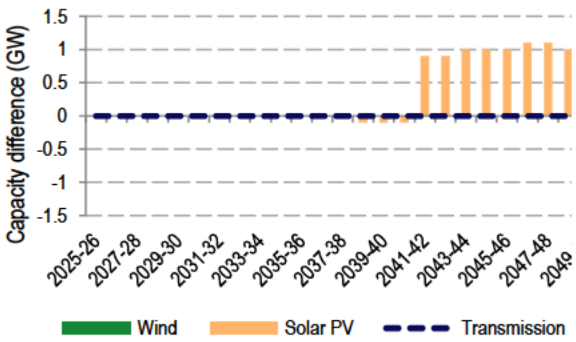
a. South-West NSW (NSW)



b. Murray River (VIC)



c. Riverland (SA)

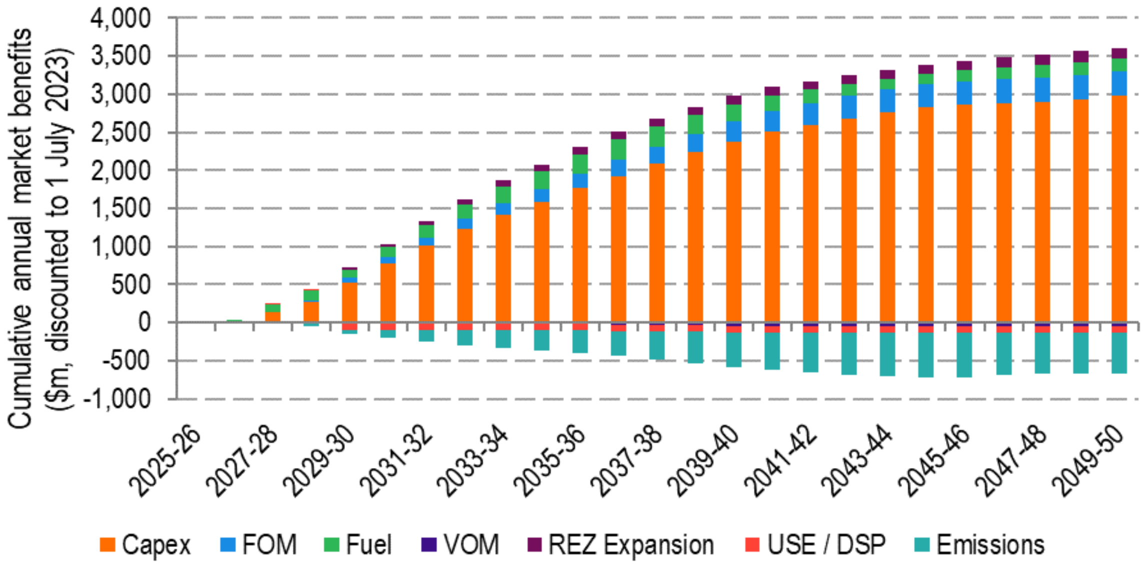


5.3 Market modelling outcomes for PEC 2 staged 26-27 Progressive Change scenario

5.3.1 Forecast gross market benefits, Progressive Change scenario

The gross market benefit forecast for PEC Stage 2 with staged commission from 1 Jul 2026 to 1 Jul 2027 in the Progressive Change scenario are shown in Figure 15 on an annual, discounted basis. Over the Modelling Period, it is forecast that PEC Stage 2 results in $2,942m in gross market benefits discounted to 30 June 2023 (in real June 2023 dollar terms).

Figure 15: Forecast cumulative gross market benefit for PEC 2 staged 26-27 under the Progressive Change scenario in the NEM; discounted to 30 June 2023 in millions of real June 2023 dollar terms



Unlike Step Change, the annual benefits of PEC Stage 2 are only forecast to begin to accrue from 2027-28 after the augmentation is fully completed.

Most of the gross market benefits in the Progressive Change scenario are again forecast to be from the reduction in expected capex costs, followed by savings from FOM, fuel and REZ expansion. REZ expansion benefits are observed from 2029-30 onwards after PEC Stage 2 is complete as the augmentation reduces the need for optional transmission build. The Progressive Change scenario is forecast to have higher capex and FOM benefits for PEC Stage 2 compared to the Step Change scenario. The reasons for this are given in Section 5.3.2.

In contrast to the Step Change scenario, there is substantial emissions disbenefit due to PEC Stage 2 allowing the replacement of gas generation in South Australia with low cost but more emissions intensive thermal generation in other regions. This effect is more prominent in Progressive Change due to the relaxed emissions budget. This is also explained further in Section 5.3.2.

5.3.2 Forecast NEM generation development plan, Progressive Change scenario

The differences in the forecast capacity and generation outlooks in the Progressive Change scenario across the NEM with and without PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 are shown in Figure 16 and Figure 17 respectively. Step Change outcomes are also repeated on the same scale for ease of comparison.

Figure 16: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Progressive Change and Step Change scenarios, relative to PEC Stage 1

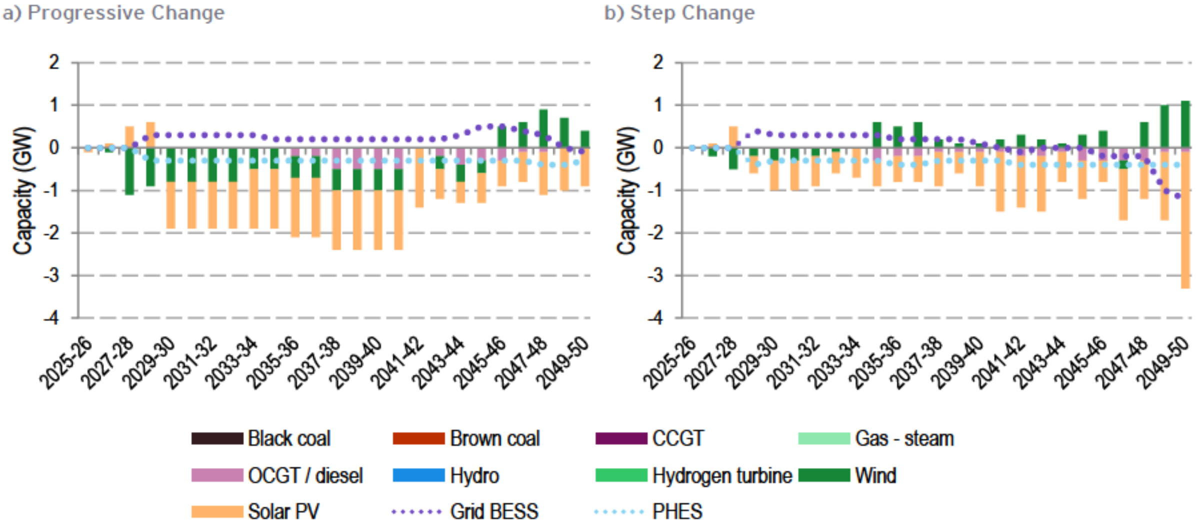
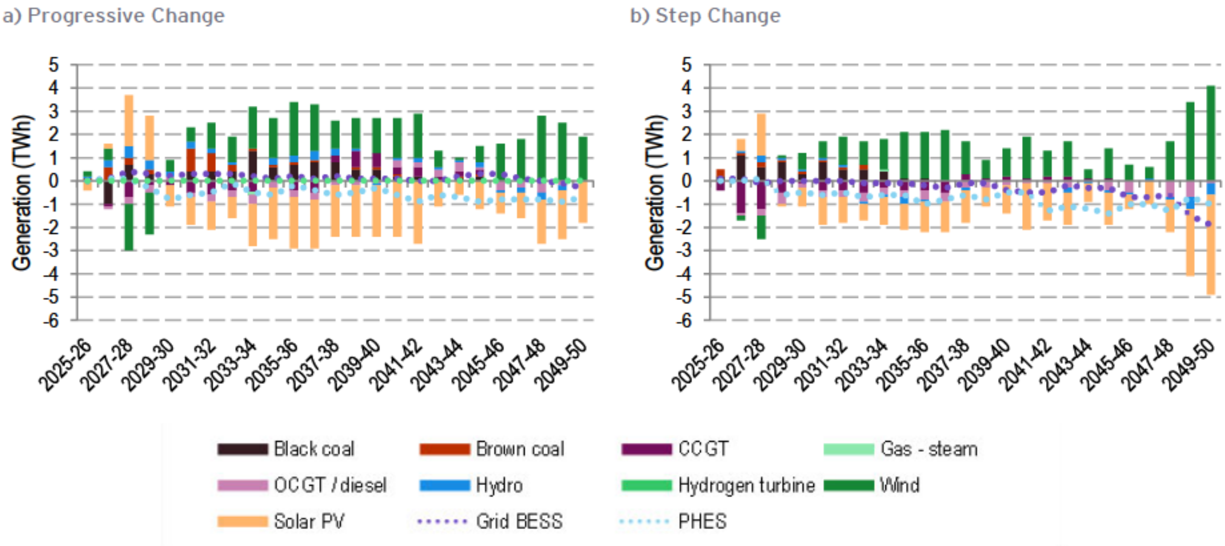


Figure 17: Forecast generation difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Progressive Change and Step Change scenarios, relative to PEC Stage 1



While continued investment in new wind and solar is forecast with PEC Stage 2, Figure 16 shows that some investment is forecast to be deferred. From 2045-46 there is forecast to be additional investment in wind with PEC Stage 2 in the Progressive Change scenario, where this is forecast to occur for the mid 2030s in the Step Change Scenario. We also see that while wind capacity is expected to be lower with PEC Stage 2 until the mid-2040s (Figure 16a), wind generation is expected to be higher as a result of increased connectivity provided by PEC Stage 2 (Figure 17a).

For both depicted scenarios, trends in renewable capacity investment due to PEC Stage 2 are broadly similar, but the magnitude of changes is more exaggerated in the Progressive Change scenario. Meanwhile, the forecast decreased investment in gas is similar to Step Change. The differences between the scenarios' capacity and generation mix can be attributed to the more relaxed emissions budget and the significant decrease in demand reductions in the late 2020s and the interaction of this with the renewable policy targets within the Progressive Change scenario.

With the assumed demand reductions and fixed coal closure dates, a significant percentage of annual energy to 2030 is met with coal-fired generators and CCGTs operating at minimum load in all PEC cases. There is then little headroom for increased coal or gas operation at times of low availability of wind and solar to meet demand while staying within the 82% renewable energy target. To meet demand while satisfying the 82% target without PEC Stage 2, some renewables are built even though they are not frequently dispatched due to the lack of emissions constraint headroom for thermal units to act as firming capacity. Some of this investment is avoided with PEC Stage 2, contributing to the higher forecast capex benefits up to 2030 in the Progressive Change scenario relative to Step Change.

However, in the Progressive Change scenario, the PEC Stage 2 case is forecast to result in higher emissions costs calculated as a post-process. The difference in forecast generation with PEC Stage 2 in Figure 17 shows an increase in black and brown coal generation, to a magnitude and frequency larger than in Step Change, especially brown coal. In both scenarios, the alleviation of system security constraints reduces gas generation in South Australia that is constrained on; this creates headroom for increased emissions from lower cost thermal generation elsewhere instead. The larger emissions budget in the Progressive Change scenario exaggerates this trend. With PEC Stage 2, existing thermal generation in New South Wales, Queensland and Victoria is forecast to increase by about 1%. The increased coal generation in the with PEC Stage 2 case further increases the avoided capacity build difference with the base case compared to Step Change as more coal generation can substitute renewable capacity, while still respecting emissions budgets and renewable energy targets. When emissions costs are calculated as a post-process, total emissions costs are higher with PEC Stage 2 due to the difference in magnitude and timing of emissions.

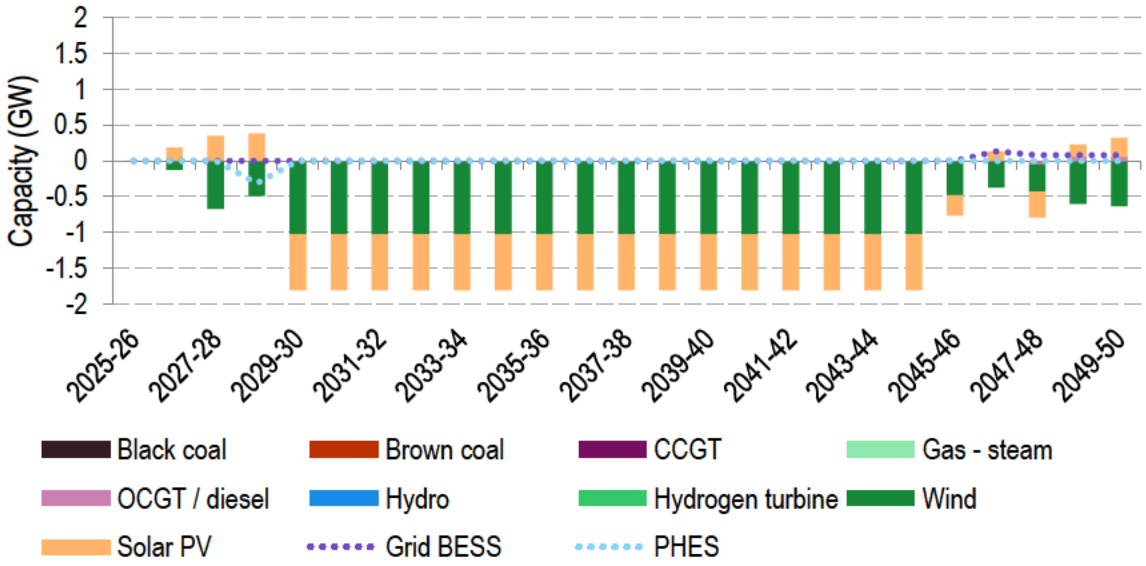
Figure 18 shows the difference in capacity with PEC Stage 2 for both New South Wales and South Australia. While Figure 16 shows wind investment is forecast to decrease on an overall NEM-wide basis until the mid-2040s with PEC Stage 2, Figure 18b shows that PEC Stage 2 is forecast to unlock greater investment in wind in South Australia. This increase is outweighed by a larger forecast decrease in investment in wind and solar in New South Wales. PEC Stage 2 provides access to higher capacity factor wind resource South Australia. Meanwhile, there is a decrease in forecast investment in OCGT/ diesel in South Australia as a result of alleviation of the South Australia non-synchronous generation constraint. By limiting renewable generation in South Australian, this constraint drive investment in gas capacity. A similar trend is observed in the Step Change scenario.

In comparison to the Step Change scenario:

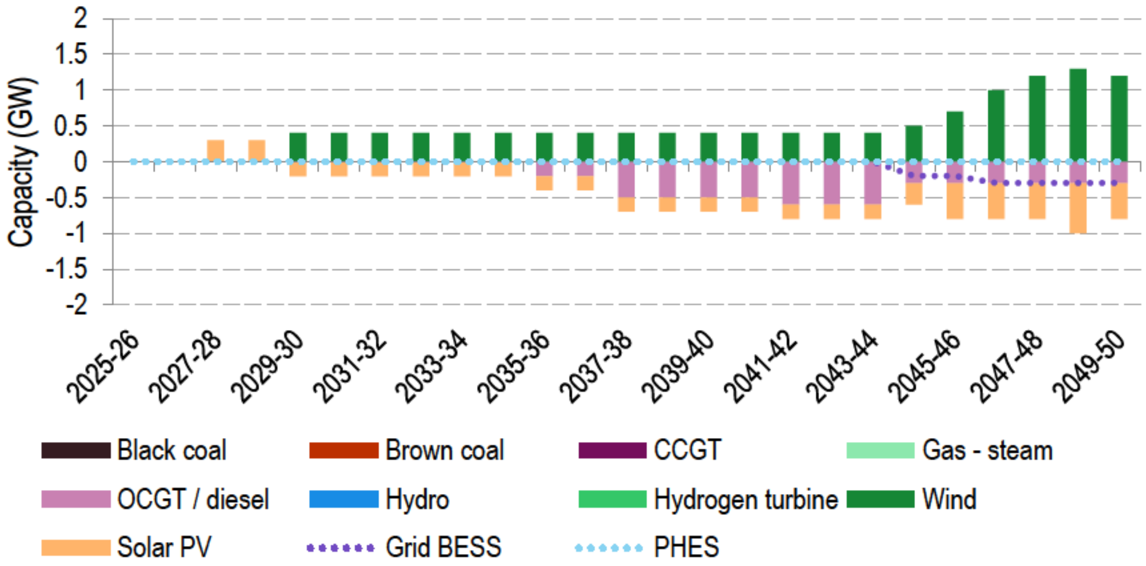
- The decrease in investment in New South Wales is more pronounced. This reflects the increase in capex savings in the Progressive Change scenario as a result of the phenomenon described above, where the interaction between the lower demand scenario, 82% renewable target and minimum load requirement of coal leads to renewable build that is not frequently dispatched in the without PEC Stage 2 case, which is avoided with PEC Stage 2.
- The increase in investment in wind in South Australian REZs is forecast to be smaller in magnitude and occur later in the Modelling Period. This is a byproduct of the lower overall capacity build in the long term due to lower demand.

Figure 18: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Progressive Change scenario, relative to PEC Stage 1

a. New South Wales



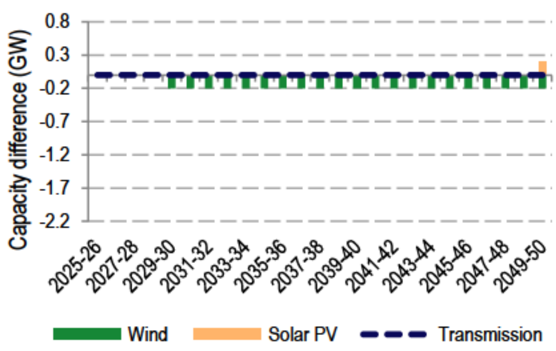
b. South Australia



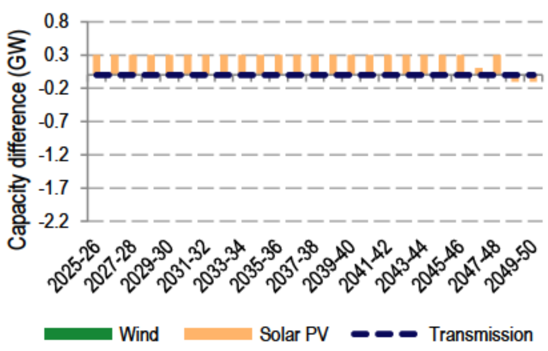
The differences in capacity outlooks with PEC Stage 2 in the Progressive Change scenario in REZs directly impacted by PEC are shown in Figure 19.

Figure 19: Forecast REZ capacity mix difference between PEC 2 staged 26-27 and PEC 1 case in the Progressive Change scenario

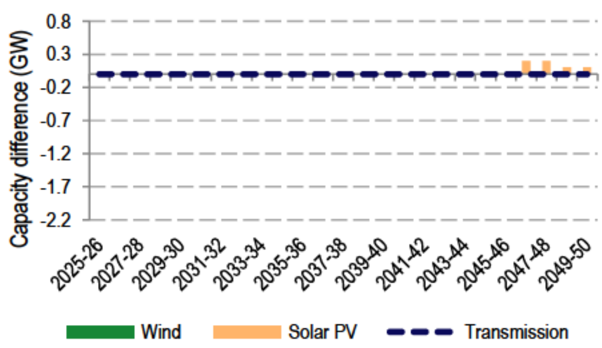
a. South-West NSW (NSW)



b. Murray River (VIC)



c. Riverland (SA)

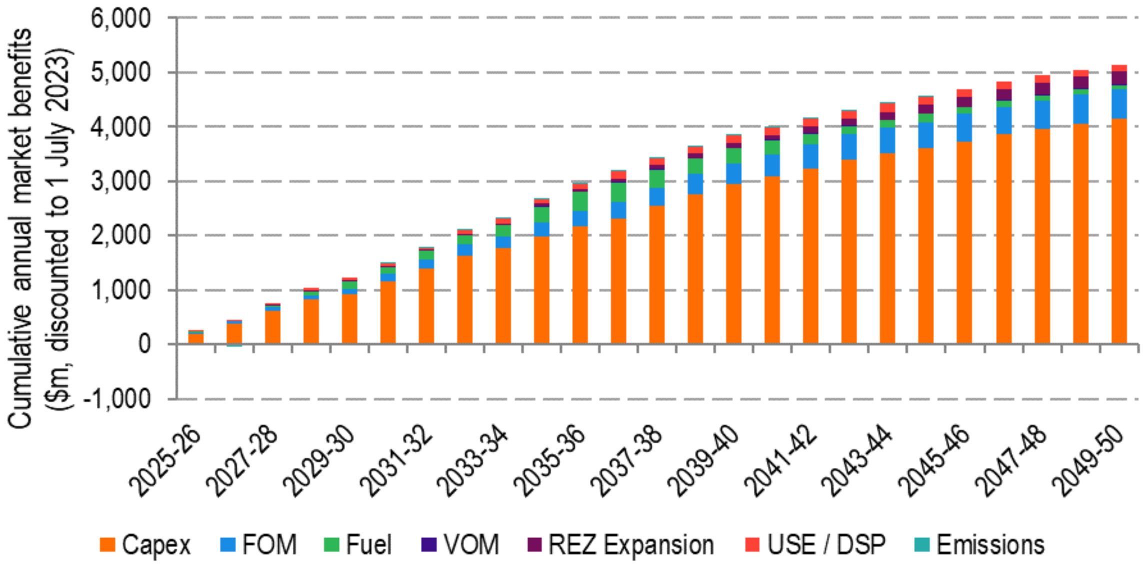


5.4 Market modelling outcomes for PEC 2 staged 26-27 Green Energy Exports scenario

5.4.1 Forecast gross market benefits, Green Energy Exports scenario

The gross market benefits forecast for PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 in the Green Energy Exports scenario are shown in Figure 20 on an annual, discounted basis. Over the Modelling Period, it is forecast that the inclusion of PEC Stage 2 results in $5,126m in gross market benefits discounted to 30 June 2023 (in real June 2023 dollar terms).

Figure 20: Cumulative annual PEC Stage 2 market benefit forecast for the Green Energy Exports scenario in the NEM, PEC 2 staged 26-27; discounted to 30 June 2023 in millions of real June 2023 dollar terms



The Green Energy Exports scenario is forecast to have higher benefits for PEC Stage 2 compared to the Step Change and Progressive Change scenario. There is a large amount of new capacity required to meet a large increase in assumed demand and the bulk of this capacity must be renewable generators and storage in order to respect the stringent carbon budget. The faster transition to renewable energy and storage gives a greater opportunity for PEC Stage 2 to be utilised and reduce investment in renewable generators, storage and gas-fired generation.

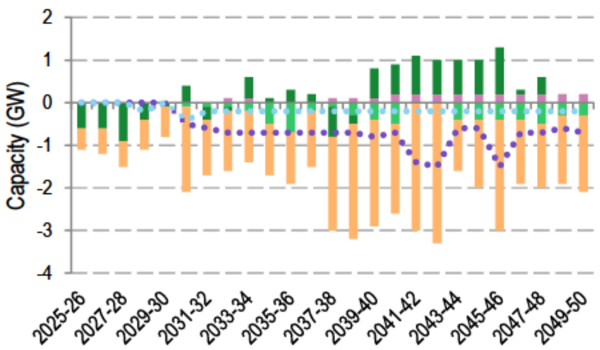
The capex savings are driven by the deferral in project expenditure, which commence in the anticipation of PEC Stage 2 commissioning. Fuel savings are driven by foreknowledge that PEC Stage 2 increases renewable support between major regions once commissioned. This provides additional headroom in the long-term emissions budget (which is a binding constraint in the model), meaning coal (higher emissions but lower cost fuels) is expected to keep generate at higher levels in place of South Australian gas (lower emissions, higher cost fuels) to minimise system cost. Assumed coal retirement dates are unchanged and the increase in emissions in the first two years are offset later so the emissions budgets are still met.

5.4.2 Forecast NEM generation development plan, Green Energy Exports scenario

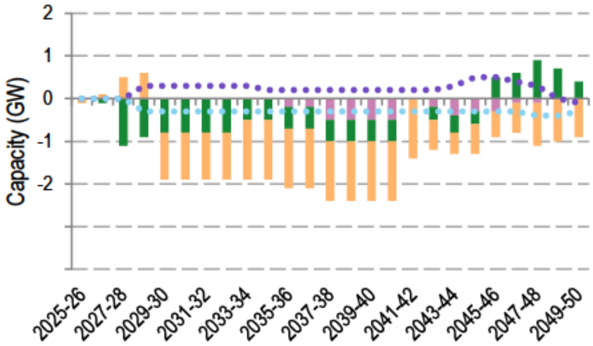
The differences in the forecast capacity and generation outlook in the Green Energy Exports scenario across the NEM with and without PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 are shown in Figure 21 and Figure 22, respectively. Progressive Change and Step Change scenario outcomes are repeated for ease of comparison.

Figure 21: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Green Energy Exports, Progressive Change and Step Change scenarios, relative to PEC Stage 1

a) Green Energy Exports



b) Progressive Change



c) Step Change

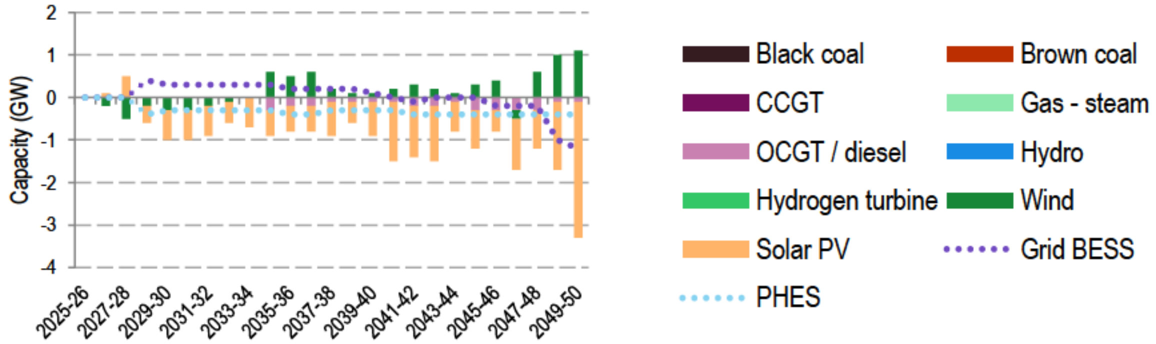
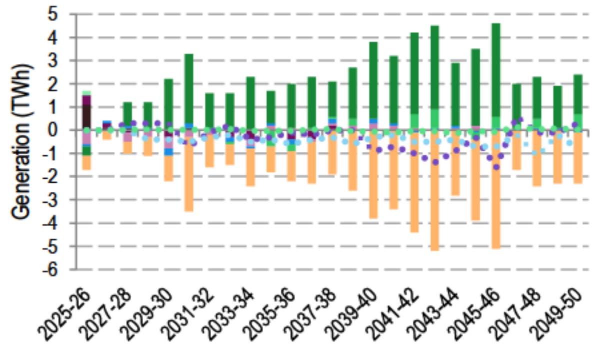
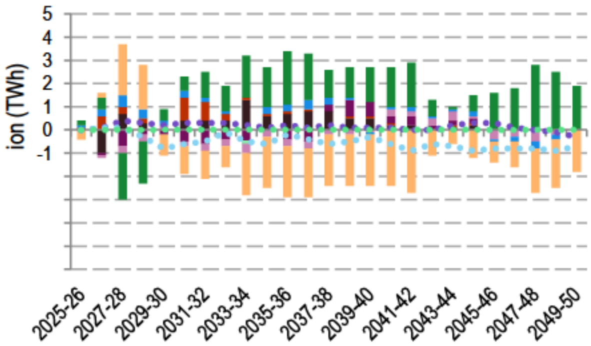


Figure 22: Forecast generation difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Green Energy Exports, Progressive Change and Step Change scenarios, relative to PEC Stage 1

a) Green Energy Exports



b) Progressive Change



c) Step Change

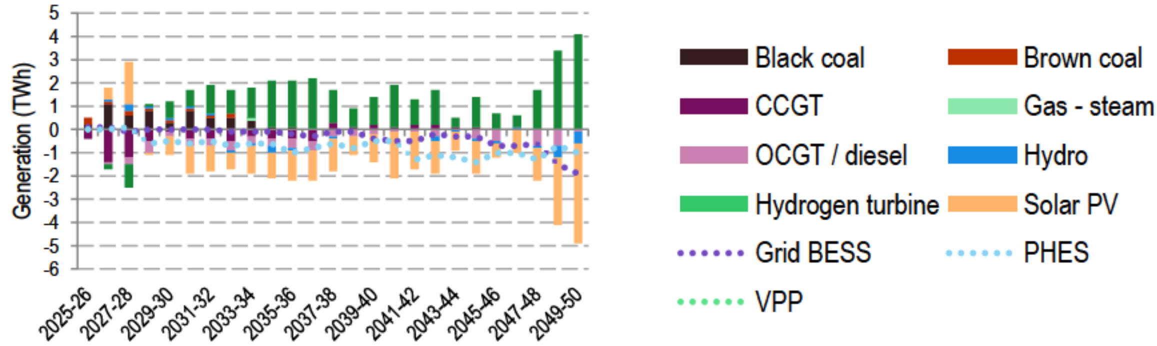


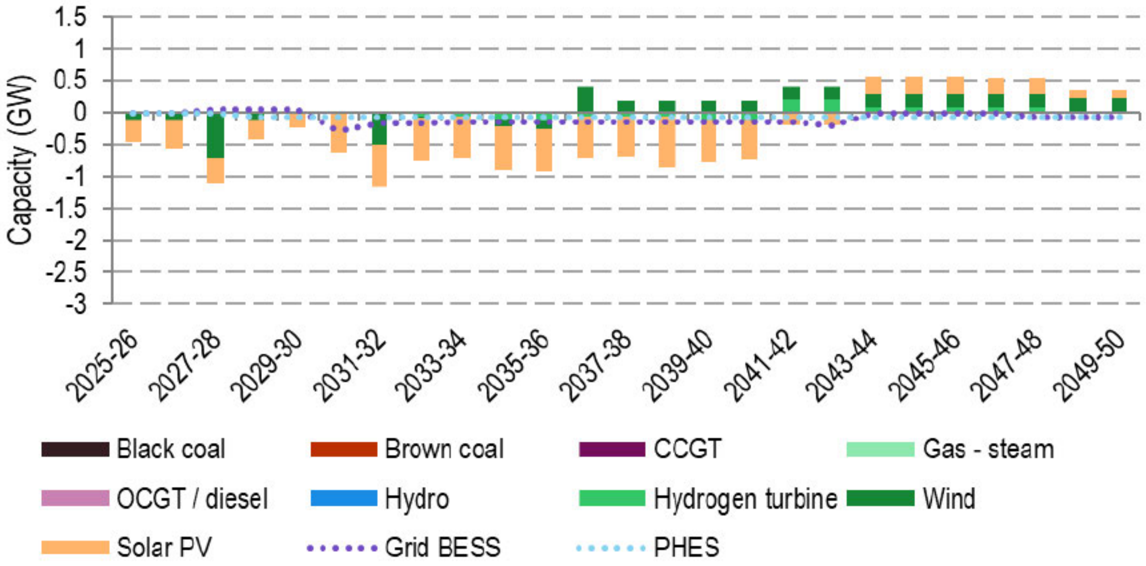
Figure 21 shows the forecast reduction in capex in the Green Energy Exports scenario is primarily due to a reduction in forecast solar PV, BESS and hydrogen turbine capacity with a small reduction in PHES investment and a deferral of wind investment. These forecast capex savings are offset by an increase in the 2040s with PEC Stage 2. The avoided investment is forecast to be greater in magnitude to the Step Change scenario and occur earlier than in the Progressive Change scenario. As a result, the capex and FOM savings are highest in the Green Energy Exports scenario.

Figure 22 shows that trends in solar and wind generation are similar in all three scenarios. PEC Stage 2 is forecast to reduce solar operation across the NEM as a result of having improved access to higher capacity factor wind generation in South Australia. In many years where wind capacity is forecast to decrease, wind generation increases. As in the Step Change and Progressive Change scenarios, there is increased coal generation with PEC Stage 2 as a result of the alleviation of South Australia system security constraints. However, in the Green Energy Exports scenario this effect is the least pronounced due to the lower emissions budget overall and the non-synchronous generation constraint being disabled for all cases in this scenario (as it is impossible to achieve a feasible solution with it enabled due to the large amounts of hydrogen demand in the scenario) which provides less emissions savings to be reallocated. Consequently, there is generally more of a difference from renewable build than the Step Change and Progressive Change scenarios, which contributes to higher capex savings.

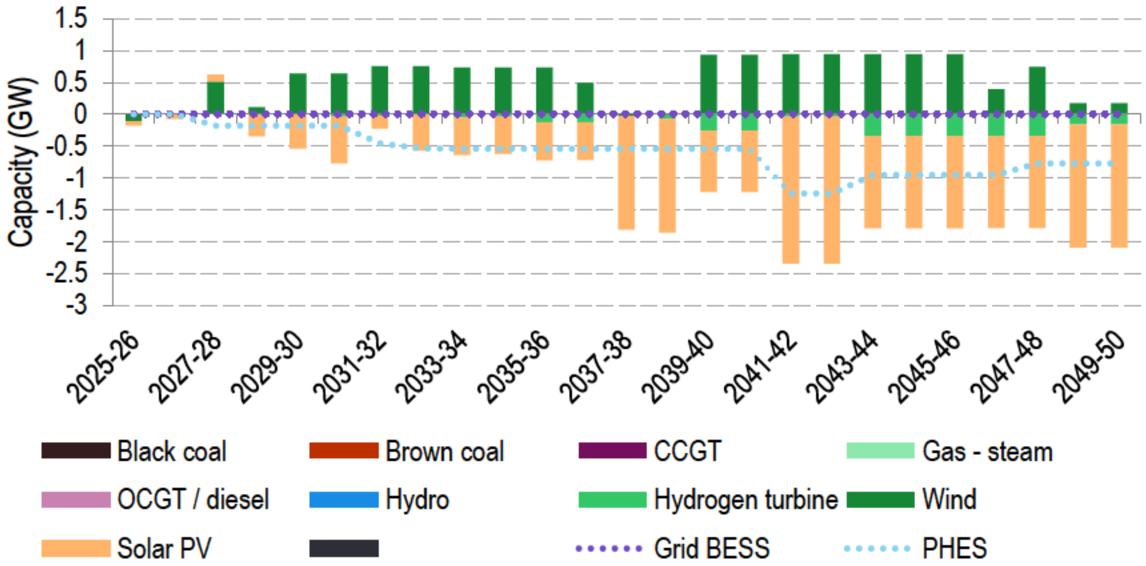
Figure 23 shows the difference in capacity with PEC Stage 2 for both New South Wales and South Australia. It shows that PEC Stage 2 is forecast to unlock greater investment in wind in South Australian. There is a forecast decrease in investment in wind and solar in New South Wales until 2037-38. In the longer-term, there is a forecast increase in wind and solar investment with PEC Stage 2 in New South Wales. There is a forecast decrease in solar, PHES and hydrogen turbine in South Australia.

Figure 23: Forecast capacity difference with PEC Stage 2, staged commissioning between 1 Jul 2026 and 1 Jul 2027 for the Green Energy Exports scenario, relative to PEC Stage 1

a. New South Wales



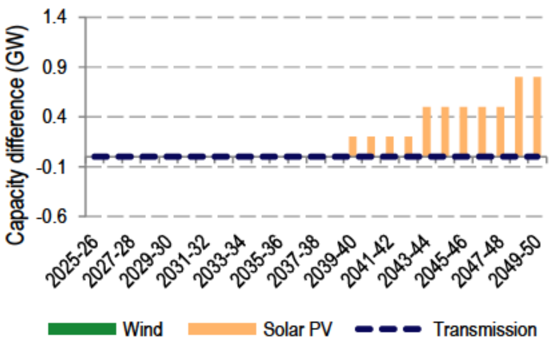
b. South Australia



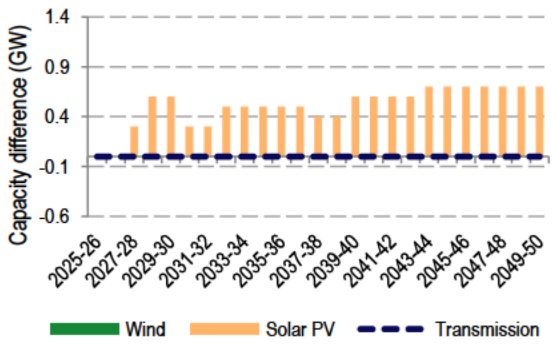
The differences in capacity outlooks with and without PEC Stage 2 in the Green Energy Exports scenario in REZs directly impacted by PEC are shown Figure 24. We see increased forecast investment in solar all these REZs with PEC Stage 2. The outcome in South-West NSW REZ contrasts with the outcomes in the other scenarios which saw decreased investment in wind in this REZ and little and later forecast increase in solar capacity. The increase in capacity differences across the REZs reflects the large volume of capacity build in this scenario due to assumed higher demand, as well as much higher land limits and therefore greater utilization of REZs.

Figure 24: Modelled REZ capacity mix difference between PEC 2 staged 26-27 and PEC 1 case in the Green Energy Exports scenario

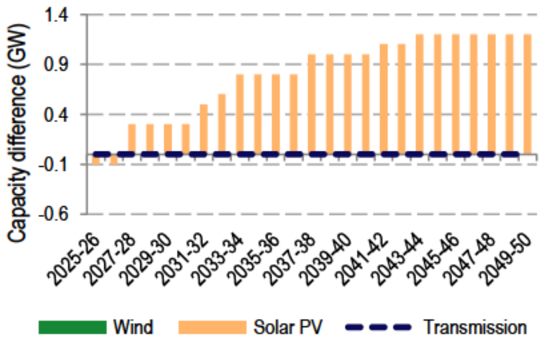
a. South-West NSW (NSW)



b. Murray River (VIC)



c. Riverland (SA)



5.5 Market Modelling outcomes for Project EnergyConnect Stage 2 with 12-month delay

This section presents the forecast gross market benefits for PEC Stage 2 across each scenario comparing the on-time delivery of the project with a 12-month delay case, as outlined in Section 3.1. The assumed commissioning dates for each case are as follows:

- PEC 2 staged 26-27: staged commissioning of PEC Stage 2 between 1 Jul 2026 and 1 Jul 2027 (on-time delivery)
- PEC 2 staged 27-28: staged commissioning of PEC Stage 2 between 1 Jul 2027 and 1 Jul 2028 (12-month delay)

The incremental market benefits for PEC Stage 2 staged 27-28 are shown in Table 8.

Table 8: Forecast incremental gross market benefits for PEC 2 staged 27-28 (12-month delay) in all scenarios; discounted to 30 June 2023 in millions of real June 2023 dollar terms

PEC option	PEC option timing	Forecast incremental gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 27-28	Staged timing from 1/07/2027-1/07/2028	3,051	2,713	4,631
PEC 2 staged 26-27	Staged timing from 1/07/2026-1/07/2027	3,214	2,942	5,126

PEC option	PEC option timing	Forecast incremental gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 27-28 minus PEC 2 staged 26-27	Reduction in benefits from the delay of PEC 2	-163	-229	-496

This Report considers only forecast gross market benefits of PEC Stage 2. Given that the cost of the two timings is expected to vary with different commissioning dates, this must also be considered in any comparison between timing. That evaluation is not part of the scope of this gross market benefits assessment hence has not been included in this Report. The calculation of net economic benefits was conducted by Transgrid outside of this Report using the forecast gross economic market benefits from this Report and other inputs.

Figure 25, Figure 26 , and Figure 27 display the forecast gross market benefits for both timing options across each of the three scenarios.

Figure 25: Cumulative annual market benefit forecast in the Step Change scenario across both PEC Stage 2 timings; discounted to 30 June 2023 in millions of real June 2023 dollar terms

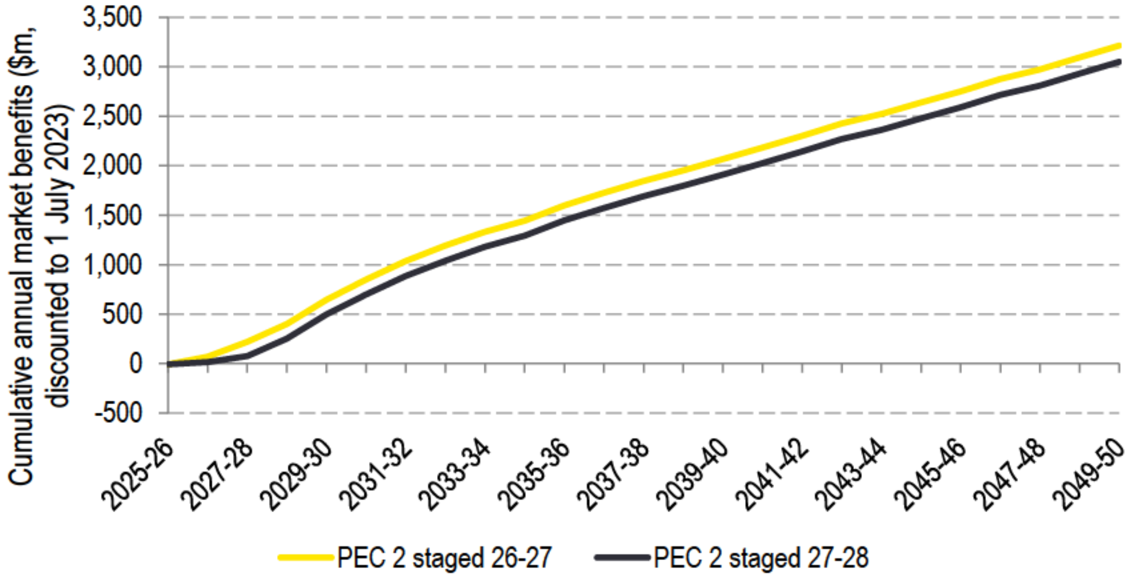


Figure 26: Cumulative annual market benefit forecast in the Progressive Change scenario across both PEC Stage 2 timings; discounted to 30 June 2023 in millions of real June 2023 dollar terms

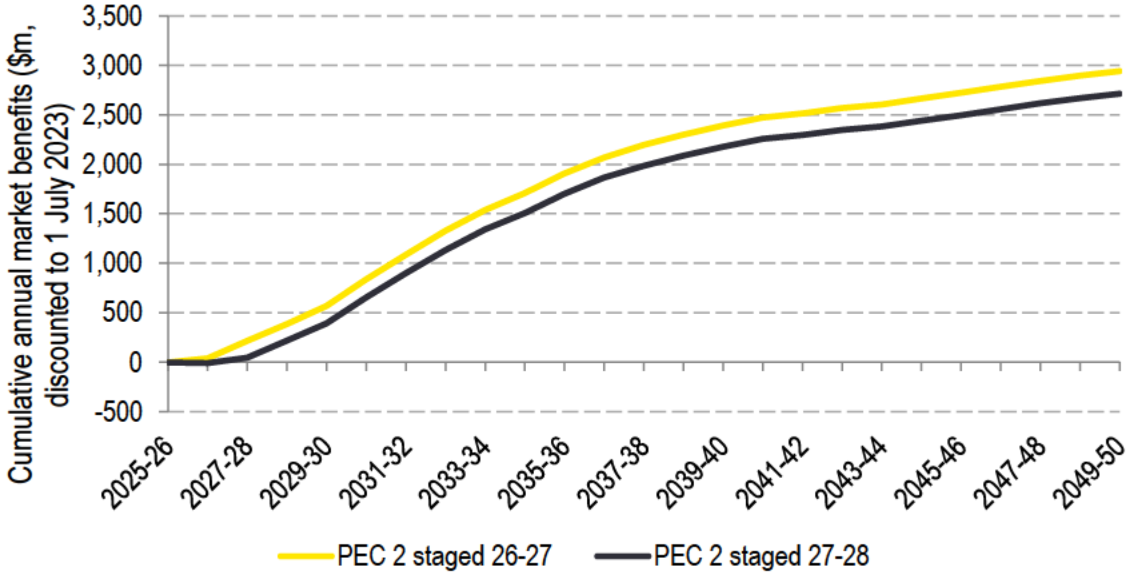
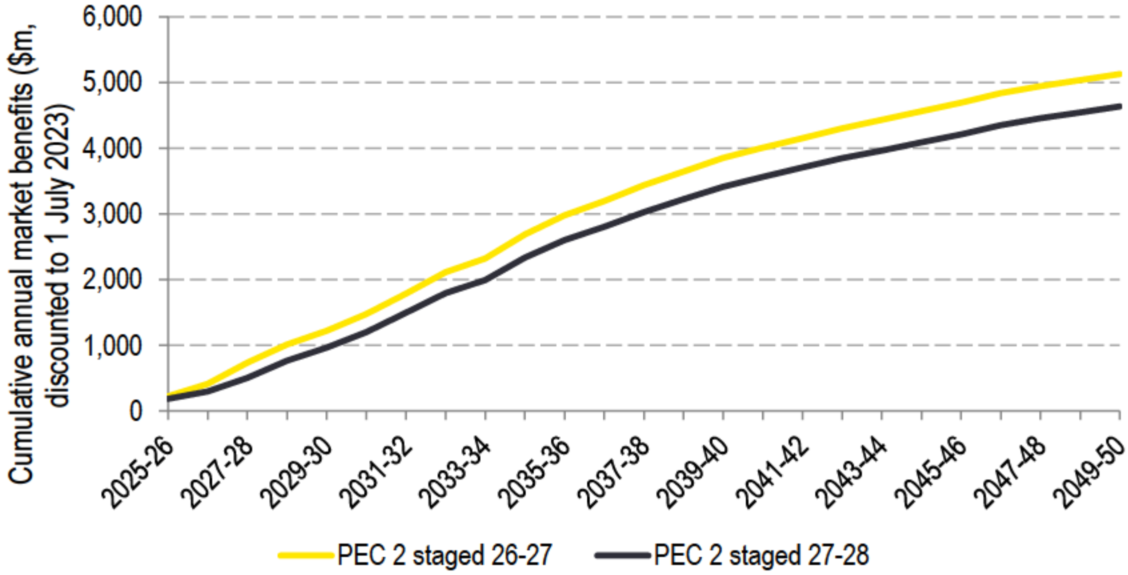


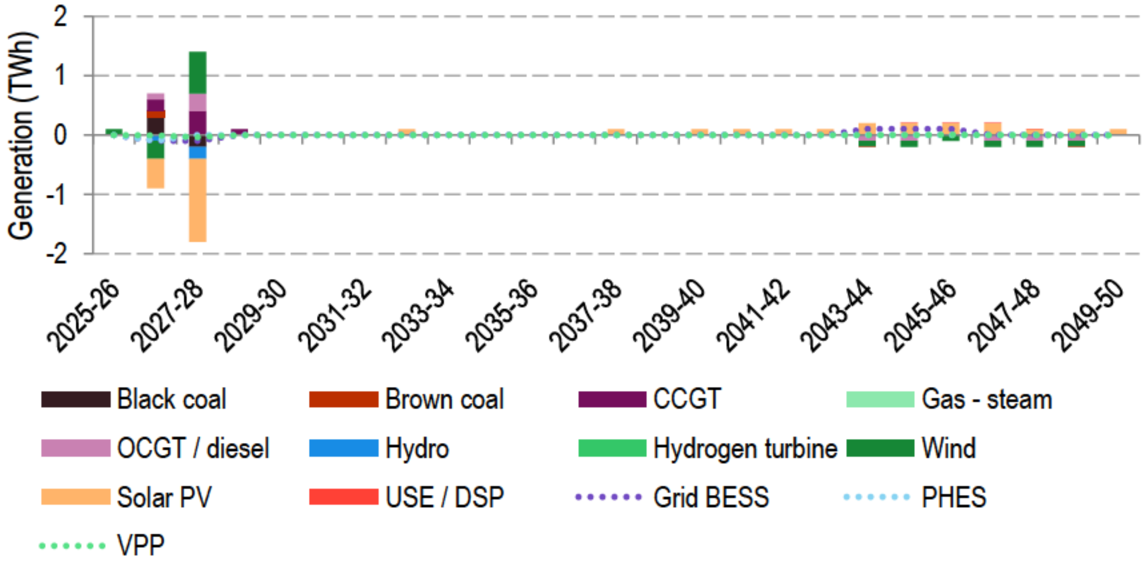
Figure 27: Cumulative annual market benefit forecast in the Green Energy Exports scenario across both PEC Stage 2 timings; discounted to 30 June 2023 in millions of real June 2023 dollar terms



Across each scenario in PEC 2 staged 26-27 and PEC 2 staged 27-28 follow a similar trend in forecast annual gross market benefits. Due to the earlier commissioning in the PEC 2 staged 26-27 case, benefits accrue earlier, leading to higher benefits.

The reduction in benefits with a 12-month delay mostly arises due to a reduction in forecast fuel cost savings as the South Australia system security constraints are assumed to be operational for an additional year. This is evident in Figure 28 which shows increased gas generation in the 12-month delay case for the two years where there is a difference in PEC 2 state (2026-27 and 2027-28). Both cases require little investment in new capacity before the South Australia system security constraints are alleviated so there is little capacity difference between the two cases and minimal differences in capex benefits.

Figure 28: Forecast generation difference with PEC 2 staged 27-28 (12-month delay) relative to PEC 2 staged 26-27 in the Step Change scenario



6. Forecast total gross market benefits outcomes

6.1 Summary of forecast total gross market benefit outcomes across scenarios

The alternative counterfactual case without Stage 1 or 2 of PEC was also modelled at Transgrid's request. As PEC Stage 1 has been built, the No PEC 1 case is a purely theoretical network state that is used to estimate gross total benefits of both stages of PEC to compare against total estimated project cost, including sunk costs. We don't attempt to forecast how the market would have developed in the absence of an expectation of PEC Stage 1 development. Any benefits already realised are thus not captured in the assessment of total market benefits.

Table 9 shows the forecast total gross market benefits of PEC Stage 2 over the 25-year Modelling Period from 2025-26 to 2049-50 in the Step Change, Progressive Change and Green Energy Exports scenarios compared to the case without PEC Stages 1 and 2. The PEC 2 staged 26-27 case represents the 'on-time' delivery of the Project while PEC 2 staged 27-28 case represents a one-year delay in delivery.

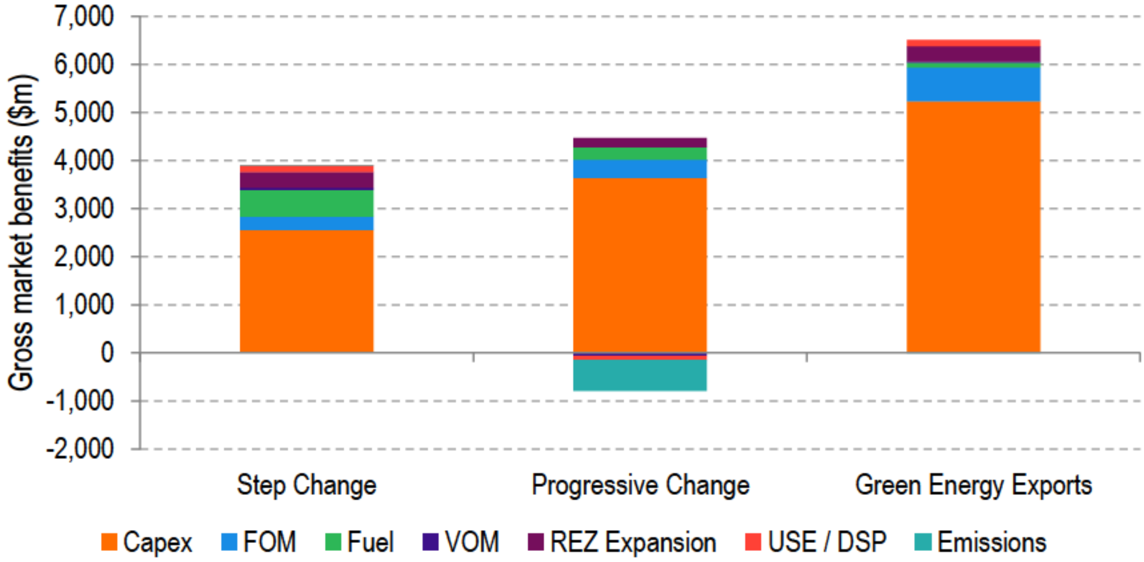
Table 9: Forecast total gross market benefits for PEC 2 staged 26-27 and PEC 2 staged 27-28 (12-month delay) in all scenarios; discounted to 30 June 2023 in millions of real June 2023 dollar terms

EnergyConnect Option	EnergyConnect Option timing	Forecast total gross market benefits		
		Step Change	Progressive Change	Green Energy Exports
PEC 2 staged 26-27	Staged timing from 1/07/2026-1/07/2027	3,906	3,682	6,504
PEC 2 staged 27-28	Staged timing from 1/07/2027-1/07/2028	3,742	3,452	6,009
PEC 2 staged 27-28 minus PEC 2 staged 26-27	Reduction in benefits from the delay of PEC 2	-163	-229	-496

The forecast gross market benefit of each scenario must be compared to the total estimated cost of the PEC Stages 1 and 2, including sunk cost, to determine the forecast net market benefit for each timing option. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by Transgrid outside of this Report using forecast gross market benefits from this Report and other inputs.

Figure 29 displays the forecast total benefits for PEC 2 staged 26-27. In all scenarios, the forecast benefits for PEC are primarily driven by capex saving across the NEM, followed by FOM savings in the Progressive Change and Green Energy Exports scenarios and fuel savings in the Step Change scenario as the second highest source of forecast benefit. Benefits for the 12-month delay in delivery of PEC Stage 2 have similar compositions of market benefits.

Figure 29: Composition of forecast total gross market benefits of PEC 2 staged 26-27 across scenarios; discounted to 30 June 2023 in millions of real June 2023 dollar terms



Overall, the distribution of forecast total benefits is similar to the incremental benefits of PEC Stage 2. The increase in the forecast total benefits of PEC compared to forecast incremental benefits stem from the benefits derived from the initial PEC 1 upgrades which directly connects South Australia to New South Wales. The increased forecast capex benefits are due to a better-connected NEM, therefore less renewable capacity needs to be installed to meet assumed demand while respecting assumed policy targets. There are also higher forecast fuel cost benefits compared to the incremental case due to increased gas generation in South Australia without PEC 1 when South Australia is less connected to the rest of the NEM. REZ expansion benefits are higher than in the incremental case, as more optional transmission must be built to meet demand in the case without PEC 1.

The reduction in forecast total gross market benefits with a 12-month delay in PEC Stage 2 is the same as the reduction in forecast incremental gross market benefits as it is a comparison of the same two cases.[27]

[27] Disbenefit of 12-month delay
= Benefit of PEC 2 staged 27-28 - PEC 2 staged 26-27
= (PEC 2 staged 27-28 minus No PEC 1/PEC 1) - (PEC 2 staged 26-27 minus No PEC 1/PEC 1)
= PEC 2 staged 27-28 - PEC 2 staged 26-27

Appendix A Methodology

A1. Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2025-26 to 2049-50. The modelling methodology follows the CBA guidelines for actionable ISP projects published by the Australian Energy Regulator.[28] The forecast gross market benefits of PEC are calculated as the difference in the system cost that is forecast with and without PEC.

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

- Capex of new generation and storage capacity installed,
- FOM costs of all generation and storage capacity,
- VOM costs of all generation and storage capacity,
- Fuel costs of all generation capacity,
- Cost of DSP and USE,
- Transmission expansion costs associated with REZ development,
- Transmission[29] and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.
- Emissions as a byproduct of thermal generation are valued according to AER's *Valuing emissions reduction* document[30] as a post-process to the optimisation, as done in the ISP 2024.[31]

To determine the least-cost solution, the model makes decisions for each hourly[32] dispatch interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched according to their SRMC, which is derived from their VOM and fuel costs, as well as technical parameters. The generation for each dispatch interval is subject to the modelled availability of power stations in each hour (subject to planned or unplanned outages or variable renewable availability), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, offshore wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES.

These hourly decisions take into account constraints that include:

- Supply must equal demand in each region for all dispatch intervals, while maintaining a reserve margin, with USE costed at the VCR,
- Minimum loads for some generators,

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[28] Australian Energy Regulator, 6 October 2023, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/reviews/review-cost-benefit-analysis-and-regulatory-investment-test-guidelines. Accessed 24 October 2024.
[29] For the transmission elements modelled, described in Appendix B.
[30] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 25 October 2024
[31] AEMO, June 2024, *ISP Appendix 6. Cost benefit analysis*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en. Accessed 24 October 2024.
[32] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly and two-hourly for Green Energy Exports as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

- Transmission interconnector flow limits (between regions),
- Maximum and minimum storage reservoir limits (for conventional storage hydro, PHES, VPP and large-scale battery),
- New entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits, and PHES in each region,
- Emissions 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 New South Wales and Victoria through modelling of zones with intra-regional limits and loss equations. The model also includes detailed representation of the Canberra zone by applying a DC load flow model. Within these New South Wales zones and within other regions, the only other element of the transmission network considered are REZ transmission constraints.[33] There are also inter-regional transfer limits (between regions). Further detail of the network model is given in Appendix B.

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

The model meets the specified carbon budget 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. The running cost for these generators is the sum of the VOM and fuel costs (and emissions costs calculated as a post-process to the optimisation). 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 interval.
- Wind and solar generators are fully dispatched according to their available variable resource in each interval, unless constrained by oversupply or network limitations.
- Scheduled storage plant of all types (conventional hydro generators with storages, PHES, large-scale battery and 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 or liquid fuel generators. Conversely, at times of low supply cost, e.g., when there is a prevailing surplus of renewable generation capacity, conventional hydro preserves energy and PHES, VPPs and large-scale batteries operate in pumping or charging mode.

A2. Reserve constraint in long-term investment planning

As per the AEMO ISP methodology[34] assumed by Transgrid, 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 may occur at any time.

[33] including an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.
[34] AEMO, June 2023, *ISP Methodology*, available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en. Accessed 1 October 2024.

All dispatchable generators in each region are eligible to contribute to reserve (except storage[35]), as is headroom that is available from interconnectors. The modelling accounts for load diversity and sharing of reserves across the NEM and so 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 single contingency reserve requirement was applied with a high penalty cost. This amount of reserve is intended to allow 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)[36].

There are two 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.

A3. Cost-benefit analysis

From the hourly (two-hourly for Green Energy Exports) time-sequential modelling, the categories of costs as listed in Appendix A1 are computed as defined in the CBA guidelines.[28]

For each scenario and sensitivity with PEC Stage 2, a matched PEC Stage 1 only or No PEC counterfactual long-term generation and investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to PEC Stage 2.

Each component of forecast gross market benefits is computed annually over the 25-year Modelling Period. In this Report, we summarise the forecast benefit and cost streams using a single value computed as the net present value (NPV)[37], discounted on an hourly basis to midnight 30 June 2023 at a 7% real, pre-tax discount rate, consistent with the 2024 IASR[9].

The forecast gross market benefits of each scenario must be compared to either the incremental estimated cost of the PEC Stage 2 (costs above PEC Stage 1), or the total estimated cost of PEC Stages 1 and 2, to determine the forecast net economic benefit. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by Transgrid outside of this Report using the forecast gross market benefits from this Report and other inputs.

[35] 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.
[36] This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.
[37] 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.

Appendix B Transmission

B1. Regional definitions

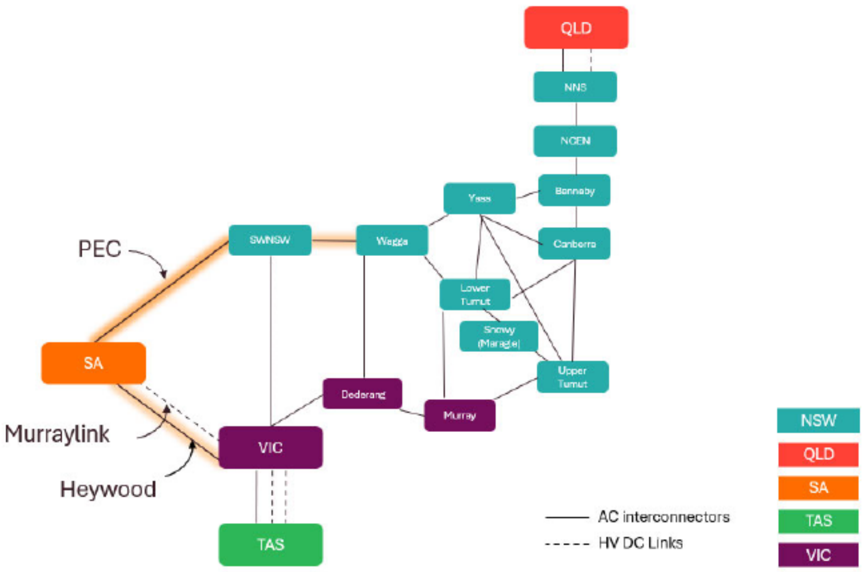
Transgrid requested to split New South Wales into sub-regions or zones in the modelling presented in this Report, as listed in Table 10. In addition, southern New South Wales and Victorian networks are modelled with higher resolution through several nodes and an overlayed DC power flow model in TSIRP. This network representation varies from that applied in the 2024 ISP but provides a more faithful model of intra-regional network limitations and transmission losses in the relevant parts of the network.

Table 10: Regions, zones and reference nodes

Region	Sub-region	Sub-regional node(s)
Queensland	Queensland (QLD)	South Pine 275 kV
NSW	Northern NSW (NNS)	Armidale 330 kV
	Central NSW (NCEN)	Sydney West 330 kV
	South-West NSW (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
	Maragle	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

To achieve a more detailed forecast of southern New South Wales and northern Victoria network flows and losses, line parameters in this area were derived by equivalencing the network connecting the relevant nodes (Bannaby, Yass, Canberra, Wagga Wagga, Lower Tumut, Upper Tumut, Maragle, Murray and Dederang), as shown below in Figure 30. The highlighted links are links impacted by the PEC upgrades. Flows were modelled using the DC load flow (DCLF) equations. DCLF is a simplified AC load flow which neglects reactive power flows. The model also captures the losses for the given lines through piecewise linear functions using the equivalent resistance of those lines.

Figure 30: Modelled nodal network diagram. Orange highlighted links are those directly impacted by PEC.[38,39]



Although PEC is part of an AC meshed network, it is modelled as fully controllable to emulate the controllability provided by phase shifting transformers in the project design.

Demand components are split across the nodes based on their half-hourly proportion of the overall New South Wales load (averaged to hourly for Step Change and Progressive Change, or two-hourly for Green Energy Exports). Generators are mapped into the nearest node.

The borders of relevant zones or regions are defined by the cut-sets listed in Table 11, as defined by Transgrid. The model considers fewer lines than the real-world network. Dynamic loss equations are defined between reference nodes across these cut-sets.

Table 11: Key cut-set definitions for the modelling

Border	Lines
NCEN-NNS	Line 88 Muswellbrook - Tamworth Line 84 Liddell - Tamworth Line 96T Hawks Nest - Taree Line 9C8 Stroud - Brandy Hill
Canberra/Yass-NCEN	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Line 4/5 Yass - Marulan Line 973 Yass - Cowra Line 999 Yass - Cowra Line 98J Shoalhaven - Evans Lane Line 28P West Tomerong - Evans Lane and new HumeLink lines from Maragle/Wagga to Bannaby from HumeLink Option 3C (Maragle-Bannaby and Wagga-Bannaby)

[38] This map is a graphical representation of the modelled network, not a map of existing or proposed transmission routes.
[39] HumeLink connections (Bannaby-Wagga, Bannaby-Maragle, Maragle-Wagga) are assumed after commissioning of HumeLink in the model (1 Dec 2026)

Border	Lines
Canberra/Yass-Bannaby	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Lines 4 &5 Yass - Marulan and new HumeLink lines from Maragle/Wagga to Bannaby from HumeLink Option 3C (Maragle-Bannaby and Wagga-Bannaby)
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
Snowy + HumeLink cut-set	As above and new HumeLink lines from Maragle/Wagga to Bannaby from HumeLink Option 3C
Wagga-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa - Albury New 330 kV double circuit from Wagga - Dinawan (after assumed commissioning of Project EnergyConnect Stage 2) New 500 kV double circuit from Wagga - Dinawan (after assumed commissioning of VNI West)
VIC-CAN	Line 060 Jindera - Wodonga Line 65 Upper Tumut - Murray Line 66 Lower Tumut - Murray
VIC-SWNSW	Line 0X1 Red Cliffs - Buronga New Red Cliffs - Buronga (after assumed commissioning of Project EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West)

B2. Interconnector and intra-connector loss models

Dynamic loss equations are computed for several conditions, including:

- Where a new link is defined e.g., NNS-NCEN, PEC Stage 1, Bannaby-NCEN, PEC Stage 2
- All the Victorian and southern New South Wales equivalenced lines between the modelled nodes, through their equivalent resistance, and
- When future upgrades involving conductor changes are modelled e.g., VNI West, QNI Connect and Marinus Link.

The network snapshots that were used as a basis to compute the loss equations were provided by Transgrid.

The southern New South Wales and northern Victorian transmission network is explicitly modelled through a DC load flow technique incorporating losses in the TSIRP.

B3. Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 12. The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in this table:

- Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW respectively. The model dispatches across the two links to minimise costs.

- Basslink + Marinus Link has combined export and import limits of 1,344 MW and 978 MW. Export and Import limits increase to 2,094 MW and 1,728 MW after Project Marinus Stage 2 (timing varies by scenario shown in Table 3).
- Snowy cut-set as defined in Table 11 has combined limit of 2,870 MW in both directions, increasing to 3,080 MW after HumeLink (1 Dec 2026).
- Snowy + HumeLink cut-set as defined in Table 11 has combined limit of 5,372 MW in both directions after HumeLink (1 Dec 2026).
- Canberra/Yass-Bannaby cut-set as defined in Table 11 has combined limit of 2,700 MW in both directions, increasing to 4,900 MW after HumeLink (1 Dec 2026).

Table 12: Notional interconnector capabilities used in the modelling (sourced from AEMO 2024 ISP[9])

Interconnector (From node - To node)	Import[40] notional limit	Export[41] notional limit
QNI[42]	1,165 MW summer/ 1,170 MW winter 2,865 MW summer/2,870 MW winter (after QNI Connect)	745 MW summer/winter 2,005 MW summer/winter (after QNI Connect)
Terranora (NNS-SQ)	150 MW summer 200 MW winter	50 MW summer/winter
PEC (Buronga-SA)	150 MW (after Stage 1) 800 MW (after Stage 2)	150 MW (after Stage 1) 800 MW (after Stage 2)
Heywood (VIC-SA)	550 MW (without PEC Stage 1) 650 MW (after PEC Stage 1) 650 MW (unchanged after PEC Stage 2)	600 MW (without PEC Stage 1) 650 MW (after PEC Stage 1) 650 MW (unchanged after PEC Stage 2)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	462 MW	462 MW
Marinus Link (TAS-VIC)	750 MW (for the first stage) 1,500 MW (after the second stage)	750 MW (for the first stage) 1,500 MW (after the second stage)
VIC-CAN[43]	Initial limit: 400 MW After VNI West and SIPS: 862 MW SIPS Contract ended 31 Mar 2032: 712 MW	Initial limit: 1,000 MW After VNI West: 1,223 MW
VIC-SWNSW[43]	Initial limit: 0 MW After VNI West: 1,207 MW	Initial limit: 0 MW After VNI West: 1,712 MW

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

[40] 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 and EnergyConnect implies eastward flow.
[41] 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 and EnergyConnect implies westward flow.
[42] Flow on QNI may be limited due to additional constraints.
[43] VIC-CAN and VIC-SWNSW are lines within the VNI cut-set. The total of these two limits was sourced from the AEMO Draft 2024 ISP, but the split between the two paths was provided by Transgrid.

Table 13: Intra-connector notional limits imposed in modelling for NSW

Intra-connector (From node - To node)	Import notional limit	Export notional limit
NCEN-NNS	930 MW summer/ 1,025 MW winter 1,230 MW (after Waratah Super Battery SIPS 1 Jul 2025) 4,270 MW (after New England REZ Network Infrastructure Project, Part 1) 3,970 MW (after Waratah Super Battery SIPS contract ends 1 Jul 2030) 6,970 MW (after New England REZ Network Infrastructure Project, Part 2)	910 MW summer/winter 3,910 MW (after New England REZ Network Infrastructure Project, Part 1) 6,910 MW (after New England REZ Network Infrastructure Project, Part 2)
Bannaby-NCEN	4,750 MW 4,500 MW post WSB SIPS project[44]	4,750 MW 4,500 MW post WSB SIPS project
WAG-SWNSW (provided by Transgrid) See Table 4 for detailed timings	700 MW (unchanged after HumeLink) 1,900 MW (in staged increments with PEC Stage 2) 3,000 MW (after VNI West) Without PEC Stage 2 (No PEC 1, PEC 1 cases), there are different uplifts applied as shown in Table 4.	500 MW (unchanged after HumeLink) 2,100 MW (with PEC Stage 2) 2,700 MW (after VNI West) Without PEC Stage 2 (No PEC 1, PEC 1 cases), there are different uplifts applied as shown in Table 4.

B4. REZ free transmission limit capabilities

The REZ transmission limit capabilities before and after transmission upgrades in the REZs with assumed upgrades are shown in Table 14. All REZs also have the option to further expand transmission limits beyond these values at an assumed cost, consistent with the 2024 ISP[9].

Table 14: REZ free transmission limit capabilities with assumed upgrades used in the modelling (sourced from AEMO 2024 ISP[9])

REZ name	REZ ID	REZ free transmission limit
North Qld Clean Energy Hub	Q2	770 MW 2,270 MW (after CopperString 2032)
New England	N2	577 MW 3,577 MW (with New England REZ Network Infrastructure Project, Part 1) 6,577 MW (with New England REZ Network Infrastructure Project, Part 2)
Central-West Orana	N3	900 MW 5,400 MW (with Central-West Orana REZ Network Infrastructure Project and Sydney Ring North)
Broken Hill	N4	250 MW
South-West NSW	N5	215 MW but group constraint for existing generators also noted 365 MW (with PEC Stage 1, unchanged with HumeLink) 1,815 MW (with PEC Stage 2) 2,715 MW (after VNI West) Without PEC Stage 2 (No PEC 1, PEC 1 cases), there are different uplifts applied as shown in Table 4.
Wagga Wagga	N6	1,100 MW 2,600 MW (with HumeLink)

[44] Waratah Super Battery SIPS contract from 1 July 2025 ending 1 July 2030, temporarily increasing export limit for the Bannaby-NCEN link

REZ name	REZ ID	REZ free transmission limit
Tumut[45]	N7	700 MW (with HumeLink)
Hunter-Central Coast	N9	400 MW 900 MW (after Hunter-Central Coast REZ Network Infrastructure Project)
Murray River	V2	440 MW summer/640 MW winter (unchanged with PEC Stage 1) 840 MW summer/1040 MW winter (with PEC Stage 2) 2,420 MW summer/2,620 MW winter (with VNI West)
Western Victoria	V3	0 MW 1,460 MW (with Western Renewables Link) 1,660 MW with (VNI West)
Riverland	S2	130 MW 280 MW (with PEC Stage 1) 930 MW (with PEC Stage 2)
North-West Tasmania	T2	277 MW summer/112 MW winter No upgrades after Marinus Link
Central Highlands	T3	527 MW summer/668 MW winter 1,217 MW summer/1,358 MW winter (after Waddamana to Palmerston upgrade)
Q1-Q6 group constraint	Q1, Q2, Q3, Q4, Q5, Q6	2,100 MW 5,100 MW (after Queensland SuperGrid South upgrade)
SWNSW REZ (N5), near Darlington Point (solar and BESS) and Broken Hill REZ (N4)[46] group constraint	N5. N4	940 MW 1,680 MW (after PEC Stage 2)
MN1 group constraint	MN1	2,000 MW 3,200 MW (after Mid-North South Australia REZ Expansion)
V3 West Transmission Limit	V3 West	780 MW summer/980 MW winter 2,220 MW summer/2,420 MW winter (after Western Renewables Link) 2,440 MW summer/2,640 MW winter (after VNI West)

[45] Wind and resource limit at Tumut is zero
[46] The SWNSW1 group generation constraint considers the following units: Broken Hill Solar Farm, Silverton Wind Farm, Broken Hill BESS, Silver City BESS, Limondale SF 1, Limondale SF 2, Sunraysia SF, Limondale BESS, Coleambally SF, Finley SF, Hillston SF, Darlington Point SF, Darlington Point BESS, Riverina BESS 1, Riverina BESS 2. Total capacity behind the constraint is 1.86 GW: 1.21 GW solar, 200 MW wind, 450 MW BESS

Appendix C Demand

The TSIRP model captures forecast demand diversity across regions by basing the overall shape of hourly demand on nine historical financial years from 2010-11 to 2018-19. Demand timeseries were provided to Transgrid by AEMO based on their ESOO 2023[47] which was adopted by AEMO for the 2024 ISP[10]. The half-hourly timeseries were converted into hourly by averaging values within each hour.

The nine reference years are repeated sequentially throughout the Modelling Period as shown in Figure 31.

Figure 31: Sequence of demand reference years applied to forecast

Modelled year	Reference year
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
2036-37	2018-19
...	...
2047-48	2011-12
2048-49	2012-13

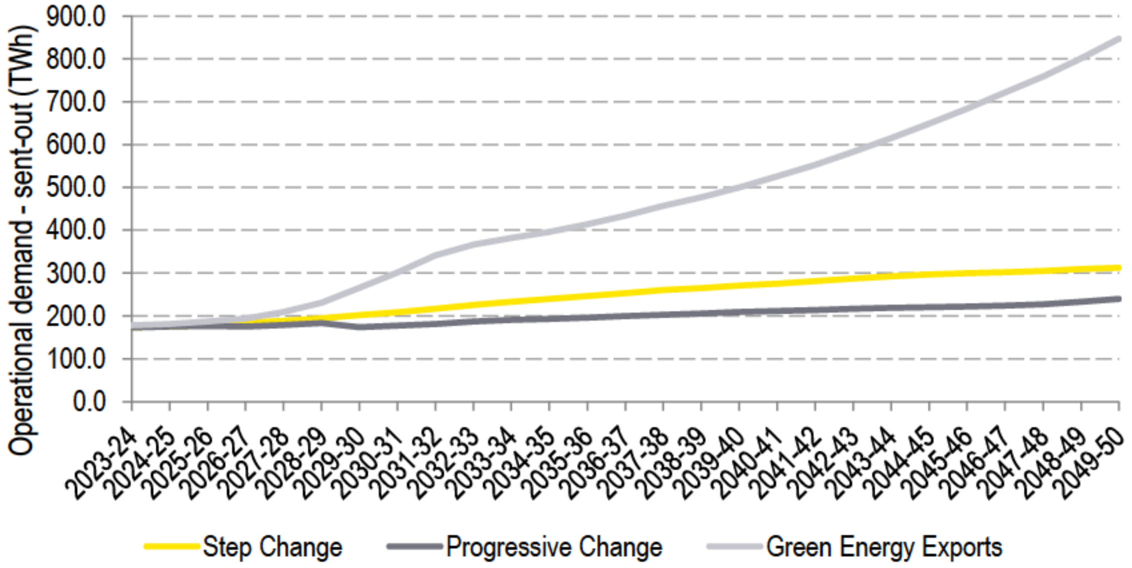
This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed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

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

[47] AEMO, August 2023, *2023 Electricity Statement of Opportunities*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 1 October 2024.

Transgrid selected demand forecasts from the ESOO 2023[48] consistent with the relevant scenarios in the 2024 IASR[9], which are used as inputs to the modelling. Figure 32 shows the assumed NEM operational demand for the modelled scenarios, inclusive of hydrogen demand.

Figure 32: Assumed annual operational demand in the modelled scenarios for the NEM



[48] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 1 October 2024.

Appendix D Supply

D1. Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations. The source of this list is AEMO's 2024 IASR Assumptions Workbook[9] for existing, committed, and anticipated projects.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[49] and the methodology for each category of wind and solar project is summarised in Table 15. All large-scale wind and solar availability profiles are developed by EY.

Table 15: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[50], 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 2021 ISP Inputs and Assumptions workbook[51,52].	
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2024 ISP Inputs and Assumptions workbook[9]. One high quality option and one medium quality option per REZ.	
Solar PV Fixed Flat Plate	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 2021 ISP Inputs and Assumptions workbook[53,52].	
	Generic REZ new entrant	Reference year specific targets based on AEMO's 2024 ISP Inputs and Assumptions workbook[9].	

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

[49] 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 1 October 2024.

[50] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo Accessed 1 October 2024.

[51] AEMO, 10 December 2021, *Input and Assumptions Workbook v3.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 1 October 2024.

[52] On the whole, capacity factor estimates for medium quality tranche wind and solar PV within a REZ have not materially changed between the 2021 IASR and the 2024 IASR for the relatively small number of committed generators.

[53] AEMO, 10 December 2021, *Input and Assumptions Workbook v3.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 1 October 2024.

demand profile. 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 31.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[54] 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 and 2024 ISP Inputs and Assumptions[9] for each REZ.

The availability profiles for solar are derived using solar irradiation data 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.

Wind and solar capacity expansion in each REZ is limited by four parameters based on the AEMO 2024 ISP Inputs and Assumptions workbook[9]:

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

AEMO's 2024 ISP input and assumptions workbook also includes intra-regional flow between nodes within Queensland and South Australia.[9] We have used a simplified nodal model for these regions in order to accommodate additional network detail in the Southern New South Wales area. As a consequence, it was not possible to model some intra-regional flows for REZ transmission limits in Queensland and South Australia while maintaining reasonable simulation times.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically (when sufficient sources of must-run generation and generation with cost at or below their VOM are available) or by other constraints such as transmission limits.

D2. 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 on the AEMO 2024 ISP input and assumptions workbook.[9]

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

[54] 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 1 October 2024.

pattern exists between the with and without PEC cases. 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 2024 ISP Inputs and Assumptions workbook.[9]

D3. Generator technical parameters

Technical generator parameters applied are as detailed in the 2024 ISP Inputs and Assumptions Workbook[9] for AEMO's long-term planning model, except as noted in the Report.

D4. 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. As with the 2024 ISP Inputs and Assumptions workbook[9], maximum loads vary seasonally. This reduces the amount of available capacity in the summer periods.

D5. 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 2024 ISP Inputs and Assumptions workbook[9], 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 dispatch interval when the cost of supply is at or above their SRMC.

D6. 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 above.

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.

D7. Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each 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 2024 ISP Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[9].

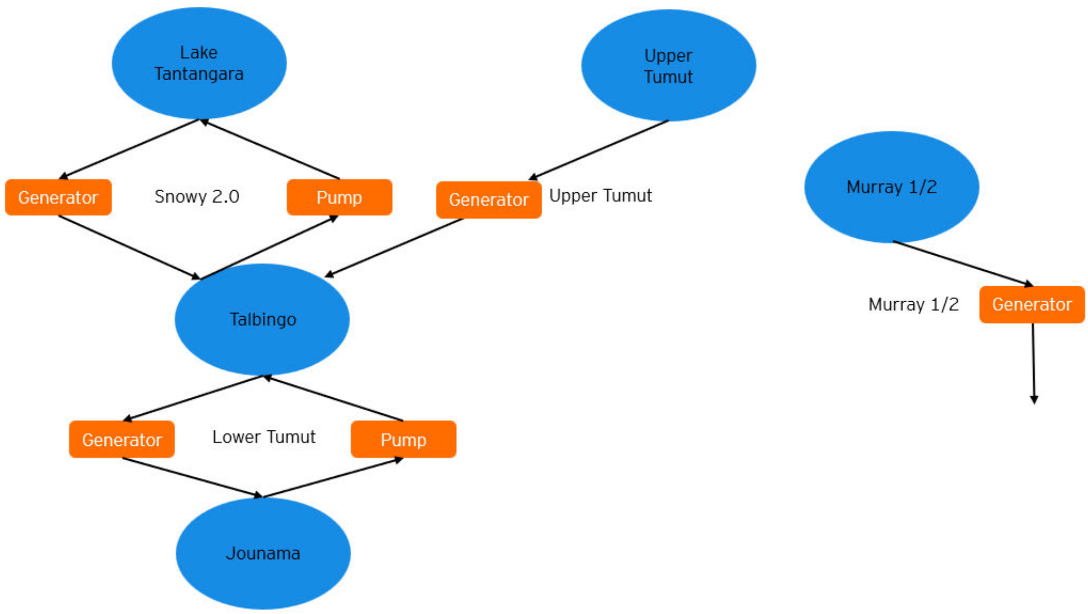
D8. Snowy 2.0 operation assumptions

In all scenarios Snowy 2.0 is assumed to be commissioned on 1 December 2028, sourced from the AEMO Generator Information published in July 2024 (in line with all other generators in the NEM)[55]. Figure 33 shows the modelled Snowy Hydro scheme[56]. In our modelling, the storage level of Talbingo reservoir factors in and tracks all the following:

- Inflows from Snowy Hydro T1/T2 (Upper Tumut) hydro scheme,
- Inflows from Tantangara reservoir due to Snowy 2.0 generation,
- Inflows from Jounama reservoir due to Tumut 3 pumping,
- Outflows to Tantangara reservoir for Snowy 2.0 pumping,
- Outflows from Tumut 3 generation to Jounama reservoir.

The methodology used to simulate operation of all water storages in the NEM is the same, and the operation of Snowy 2.0 is an example of how the storages are used to deliver the least cost solution most effectively.

Figure 33: Snowy Hydro scheme topology[57]



The storage capacity of Snowy 2.0 is approximately equivalent to seven days of continuous operation. The model assumes that the storages for the upper and lower ponds are set at the start of the modelling period to a value between maximum and minimum. Since the TSIRP optimisation provides Snowy 2.0 with perfect foresight, it finds the most beneficial time to generate, typically during high fuel cost periods, which tend to coincide with lower intermittent renewable generation levels, and the most beneficial time to pump, typically in low fuel cost periods, which tend to coincide with higher intermittent renewable generation levels. The methodology then offsets each MWh of generation by an equivalent amount of pumping, taking into account the cyclic efficiency of Snowy 2.0, which is assumed as 76%[9]. The methodology allocates matching amounts of generation

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[55] AEMO, July 2024, *NEM Generation Information July 2024*. 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 1 October 2024.

[56] AEMO, July 2020, *Market Modelling Methodologies*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf. Accessed 1 October 2024.

[57] AEMO, July 2020, *Market Modelling Methodologies*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf. Accessed 1 October 2024.

and pumping to Snowy 2.0, until the benefit of another MWh of Snowy 2.0 generation matches the cost of fuel to pump to balance that generation. Any additional cycling operation for which the costs exceed the benefits is prevented. The model also accounts for the upper and lower pond minimum and maximum levels and prevents these being breached, even if the market signal favours more cycling if possible.

The model is a long-term optimisation, which is equivalent to considering weather forecasts up to seven days in advance in the operation of Snowy 2.0. Consequently, the breakeven point for the marginal cost of generating and pumping may rise or fall over time, by day, week or season. In times of relative scarcity in cheap resources, typically when wind, solar or thermal resources are not plentiful, the marginal cost at which Snowy 2.0 generates is expected to increase to conserve water. Conversely, if there is low marginal cost generation available to pump, the marginal cost of generation from Snowy 2.0 is expected to also reduce.

Appendix E South Australia system security constraints

Constraints to meet sufficient system security requirements in South Australia were modelled as per AEMO's 'Transfer Limit Advice – System Strength in SA and Victoria[58] document, Table 1. Transgrid advised that constraints would apply in the absence of PEC and with PEC Stage 1 only.

There are two sets of constraints:

- One constraint limits the dispatch of non-synchronous generators in South Australia to <=2,500 MW in each dispatch interval.
- A second set of constraints constrains on different combinations of gas generators in South Australia.

E1. South Australia non-synchronous dispatch constraint

A non-synchronous generation constraint was applied as part of the requirements outlined in Table 17 derived from the above-mentioned document[58] constraining all non-synchronous generation (renewables and storage) to less than 2,500 MW per hourly dispatch period without PEC Stage 2 to ensure a minimum level of synchronous generation. This constraint applies throughout the entire Modelling Period in the absence of PEC Stage 2.

E2. South Australia gas constraint

The selection of units constrained on to meet the South Australia gas constraint was based on analysis of the cost of the constraint given for different combinations of units to model the least-cost solution to meeting system security requirements in South Australia.

To determine the least-cost combination of units to meet system strength requirements, we analysed the forecast dispatch of existing units in a simulation without system strength constraints. The cost to constrain on existing South Australia gas units to their minimum load was calculated by computing the shortfall in dispatch to meet minimum load multiplied by the SRMC for each hourly dispatch period. The South Australian gas units were then ranked by cheapest to constrain on to minimum load.

The following minimum load parameters for each gas unit were considered based on the 2024 IASR v6.0[9]:

- Torrens Island B: 40 MW (1 unit)
- Pelican Point: 60 MW (GT only, 1 unit)
- Osborne: 60 MW (GT only, 1 unit)
- Quarantine: 73.5 MW (unit 5)
- Barker Inlet Power Station: 30 MW (4 units)

The following retirement dates of gas units in Table 16 were modelled.

Table 16: South Australia gas units retirement dates as per AEMO July Generation Information[11]

	Torrens Island B	Pelican Point	Osborne	Quarantine	Barker Inlet Power Station
Retirement date	1 Jul 2026	1 Jul 2037	31 Dec 2026	1 Jul 2053	1 Jul 2044

[58] AEMO, April 2024, *Transfer Limit Advice – System Strength in SA and Victoria*, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf. Accessed 1 October 2024

The calculation is as follows for each dispatch period:

$$\textit{Cost to achieve minimum load } (\$) = \textit{energy shortfall } (\mathrm{MW}) * \mathrm{SRMC}\left(\frac{\$}{\mathrm{MW}}\right)$$

$$\textit{where energy shortfall } (MW) = max(\textit{minimum load}(MW) - \textit{ generation as gen } (MW), 0)$$

$$\textit{and SRMC } (\$) = (\textit{annual nominal dispatch cost})/(\textit{generation as gen over a year } (GWh))$$

The cost per hourly dispatch period is summed over each year for each unit.

The merit order of cheapest units to constrain on from this analysis were found to be:

$$\textit{Barker Inlet Power Station} < \textit{Pelican Point} < \textit{Osborne} < \textit{Quarantine}$$

This aligns with the combinations of units to meet system strength requirements summarised in Table 17, where combinations are from AEMO's document[58].

Table 17: Combinations of units to constrain on to meet system strength requirements in South Australia

Combination	Non-sync generation level	Syn Cons	Pelican Point	Osborne	BIPS
SA 6	≤ 2,500 MW	4	1	1	
SA 13	≤ 2 500 MW	4	1		4
SA 17	≤ 2 500 MW	4		1	4
SA 22	≤ 2 500 MW	4	2		

The below constraints were formulated from the least cost dispatch merit order in Table 17 to meet the South Australia gas constraint and applied in each hourly dispatch interval:

$$\textit{Barker Inlet Power Station} \geq 30\ MW\ (4\ \textit{units minimum load})$$
$$\textit{Pelican Point CCGT} \geq 60\ MW\ (1\ \textit{unit minimum load})$$
$$\textit{Osborne} \geq 60\ MW\ (1\ \textit{unit minimum load})\ \textit{if Pelican Point is unavailable}$$

Combinations SA_6 and SA_17 no longer apply after Osborne retires in Dec 2026.

The South Australia gas constraint is assumed to apply until 2037 in the absence of PEC Stage 2 as this is the retirement date of Pelican Point, after which the only GTs left are Barker Inlet Power Station and Quarantine, where other liquid fuelled units without a minimum load are required to be able to meet system strength requirements. Constraining liquid fuel units is not seen as a credible scenario to achieve system security[59].

The constraint is alleviated with PEC Stage 2 in the cases with PEC Stage 2.

[59] From 2037 there may be more credible solutions to alleviate the South Australia gas constraint including building synchronous condensers. We did not attempt to evaluate these costs. If the cost of such a solution was included in the base case it would result in higher benefits for PEC Stage 2. Given this, and the uncertainty around the cost of a solution, Transgrid have opted for a conservative view on benefits which is to turn off the constraint from 2037 without considering the costs to allow this to happen.

Appendix F Forecast flow duration curves for SA interconnectors

Figure 34: Forecast flow duration curve for PEC in both the PEC 1 and PEC 2 staged 26-27 cases in 2049-50 for the Step Change scenario. Negative flows are eastward (South Australia to New South Wales) and positive flows are westward (New South Wales to South Australia).

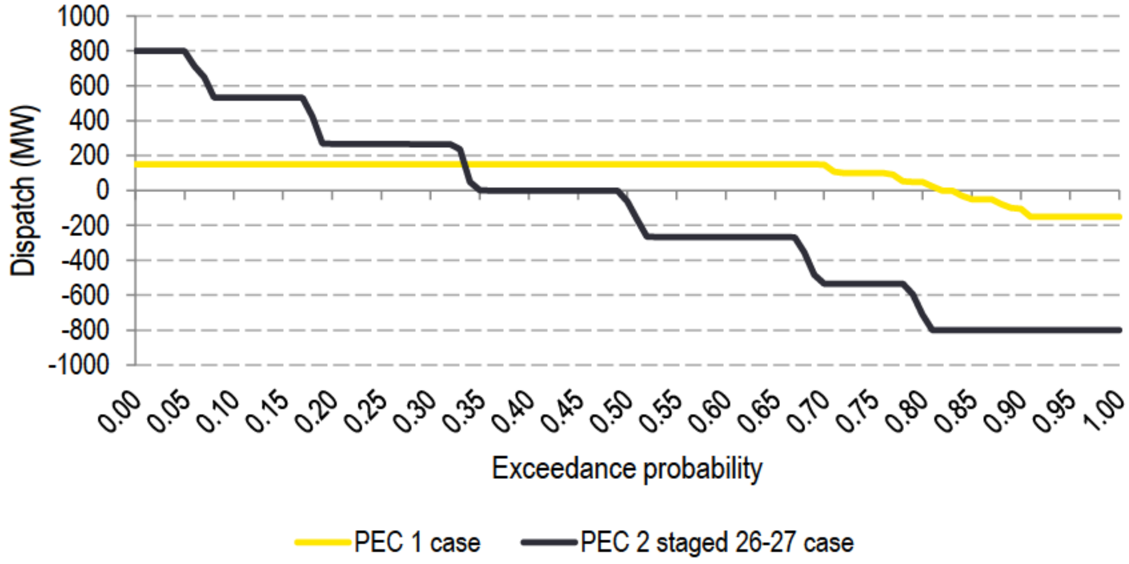


Figure 35: Forecast duration curve for Heywood in both the PEC 1 and PEC 2 staged 26-27 cases in 2049-50 for the Step Change scenario. Negative flows are eastward (South Australia to New South Wales) and positive flows are westward (New South Wales to South Australia).

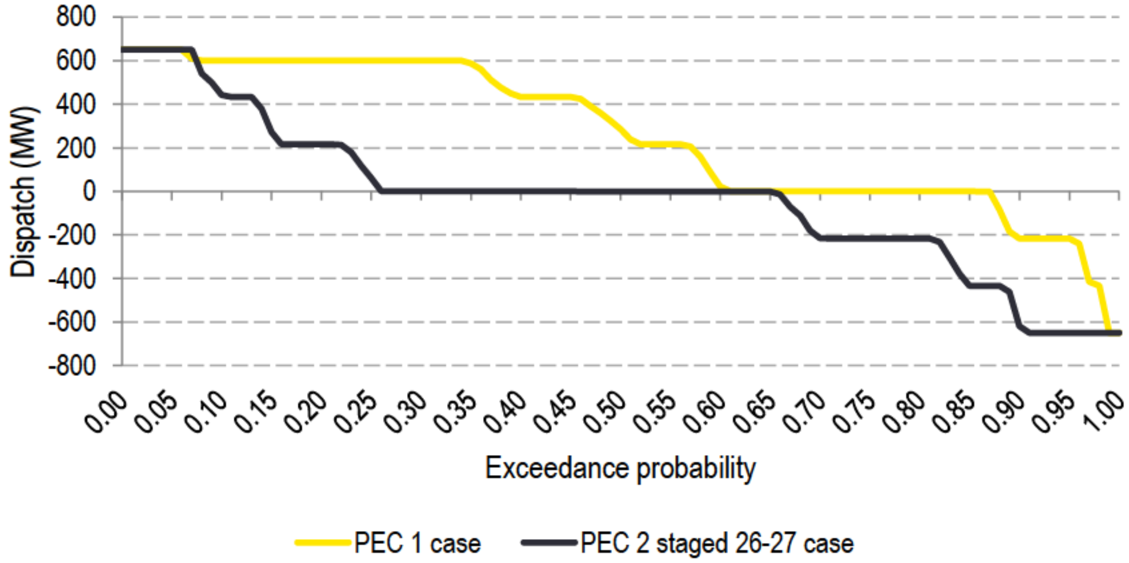
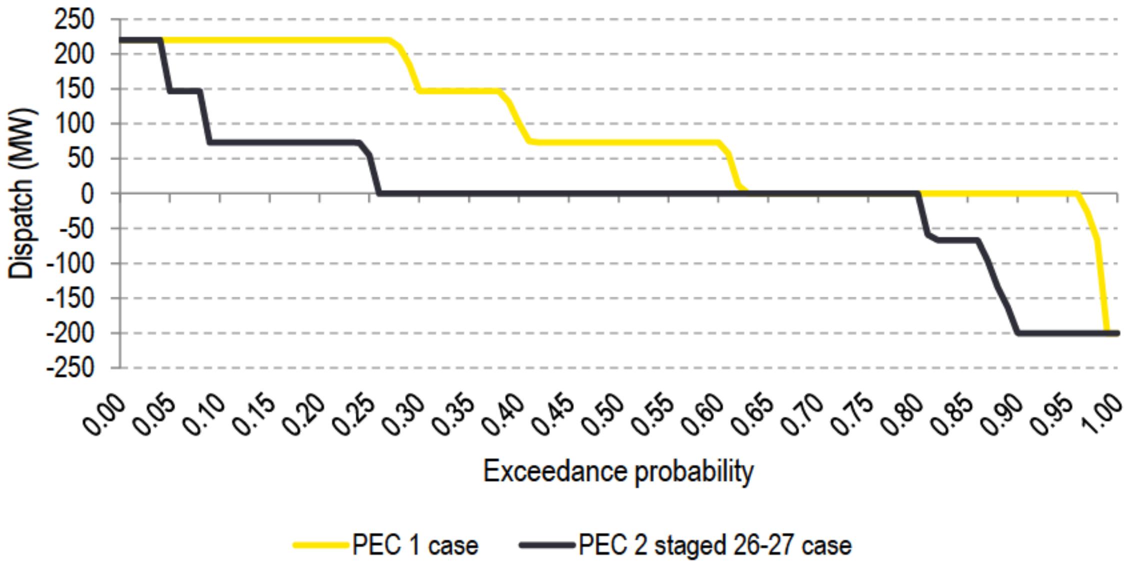


Figure 36: Forecast flow duration curve for Murraylink in both the PEC 1 and PEC 2 staged 26-27 cases in 2049-50 for the Step Change scenario. Negative flows are eastward (South Australia to New South Wales) and positive flows are westward (New South Wales to South Australia).



Appendix G Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Capex	Capital Expenditure
CBA	Cost Benefit Analysis
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
DSP	Demand Side Participation
ESOO	Electricity Statement of Opportunities
FOM	Fixed Operation and Maintenance
GT	Gas Turbine
GW	Gigawatt
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
IASR	Inputs, Assumptions and Scenarios Report
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
ODP	Optimal Development Path
PEC	Project EnergyConnect
PHES	Pumped Hydro Energy Storage
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone

Abbreviation	Meaning
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
ST	Steam Turbine
SWNSW	South-West New South Wales
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
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
WACC	Weighted Average Cost of Capital

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