Gross market benefit assessment of HumeLink

28 February 2024

Building a better working world

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Release Notice

Ernst & Young ("EY") was engaged on the instructions NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (Transgrid or the "Client") to undertake market modelling of system costs and benefits to forecast the gross benefit of HumeLink (the "Project"), in accordance with the purchase order dated 27 November 2023 ("the Engagement Agreement").

The results of EY's work are set out in this report ("Report"), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by the Client. The modelled scenarios represent three possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

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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 to New South Wales demand centres. The proposed network augmentation, known as HumeLink would comprise around 365 km of additional 500 kV transmission lines and supporting equipment, connecting the greater Sydney load centre with the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect (PEC) in South-West New South Wales (SWNSW).

This work was requested by Transgrid to inform their assessment of whether there has been a material change in circumstances for HumeLink since the Regulatory Investment Test for Transmission (RIT-T) was completed in 2021.

This work was requested by Transgrid to inform their assessment of whether the increase in the estimated capital costs for the HumeLink project constitutes a material change in circumstance (MCC) as contemplated in the National Electricity Rules, that would change the identification of the preferred option in the 2021 Regulatory Investment Test for Transmission (RIT-T) and may require re-application of the RIT-T. For the purposes of this Report we refer to this as whether an 'MCC event' has occurred (as defined in MCC Assessment report, prepared and published by Transgrid).[1]

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by the Client and the modelling methods used.

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) for three scenarios: Step Change, Progressive Change and Green Energy Exports. These combine input assumptions including:

- policies, costs and generator technical parameters from the Australian Energy Market Operator's (AEMO) Inputs, assumptions and scenarios (IASR) workbook (which details input assumptions to the Draft 2024 Integrated System Plan (ISP))[2],
- operational demand projections consistent with the Draft 2024 ISP provided to Transgrid by AEMO for use in this assessment
- assumed timing of major transmission upgrades based on the Draft 2024 ISP outcomes[3],
- coal-fired generator retirement dates based on the Draft 2024 ISP outcomes.

Although some scenario names overlap with the HumeLink RIT-T completed in 2021[4], such as the Step Change scenario, the underlying assumptions are different. These scenarios adhere to the following philosophies, developed by AEMO in consultation with their stakeholders[5]:

- 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 2021 AEMO IASR Step Change scenario.

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[1] Transgrid, 29 February 2024, *Reinforcing the NSW Southern shared Network to increase transfer capacity to demand centres (HumeLink): Material change in circumstance assessment*. Available at: https://www.transgrid.com.au/projects-innovation/humelink

[2] AEMO, December 2023, Draft *2024 Inputs, assumptions and scenarios workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024.

[3] AEMO, 15 December 2023 Draft *2024 ISP.* Available at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024.

[4] Transgrid, 29 July 2021, *Transgrid HumeLink PACR*. Available at: https://www.transgrid.com.au/projects-innovation/humelink. Accessed 7 February 2024.

[5] AEMO, July 2023, *2023 IASR Report*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en. Accessed 7 February 2024

- Progressive Change: Aims to meet Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. 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 2021 AEMO IASR Hydrogen Superpower scenario. Assumed demand across the NEM is highest in this scenario.

Common policy settings across all three scenarios include the Federal Government's 82% renewables target by 2030, New South Wales (NSW) Electricity Infrastructure Roadmap target, Queensland Renewable Energy Target, Tasmanian Renewable Energy Target, Victorian Renewable Energy Target, Victorian Energy Storage Target and the Victorian Offshore Wind Target.

The market modelling methodology follows the *Cost benefit analysis guidelines* (CBA guidelines) published by the Australian Energy Regulator (AER)[6] which contain the applicable RIT-T guidelines for actionable ISP projects including HumeLink. The model was used to compute a generation development plan without HumeLink and with three different HumeLink augmentation options across the three aforementioned scenarios. The three options assessed were:

- Option 1C-new, commissioned 1 July 2028: constructing a new double circuit 500 kV line between Maragle and Bannaby;
- Option 2C, commissioned 1 July 2028: constructing four new 500 kV lines between Maragle, Wagga Wagga and Bannaby; and
- Option 3C (the RIT-T preferred option, which is now the HumeLink Project (the "Project")), commissioned 1 July 2026: constructing three new 500 kV double-circuit lines between Maragle, Wagga Wagga and Bannaby in an electrical 'loop'.

To assess the least-cost solution with and without HumeLink, EY's Time Sequential Integrated Resource Planner (TSIRP) model was used. It makes decisions for each hourly 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 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[7].

The hourly 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,
- interconnector flow limits (between regions) and intra-regional transmission network flow limits with a focus on the southern NSW region for network options outlined above,
- maximum and minimum storage (conventional storage hydro, PHES, virtual power plant (VPP) and large-scale battery) reservoir limits and cyclic efficiency,

[6] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 1 February 2024.

[7] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine, PHES = Pumped Hydro Energy Storage.

- new entrant capacity build limits for wind and solar for each REZ where applicable, and PHES in each region,
- carbon budget constraints, as defined in the ISP for the modelled scenarios, and
- renewable energy targets where applicable by region or NEM-wide.

From the hourly time-sequential modelling we computed the following costs, as defined in the CBA guidelines[6]:

- 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,
- retirement/rehabilitation costs to cover decommissioning, demolition and site rehabilitation.

The forecast gross market benefits capture the impact of 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 with HumeLink case and the without HumeLink Base Case across the 25-year period (the Modelling Period), from 2024-25 to 2048-49. The difference in the calculated present value of costs is the forecast gross market benefits[8] due to HumeLink. Benefits presented are discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the Draft 2024 AEMO ISP[2]. This discount rate is higher than those applied in previous HumeLink studies for the RIT-T reflecting the increase in the central value for the discount rate assumed by AEMO since then. As such the outcomes detailed below are not directly comparable.

Table 1: Overview of forecast gross market benefits for HumeLink across scenarios over the Modelling Period; discounted to 1 July 2023 in millions of real June 2023 dollar terms

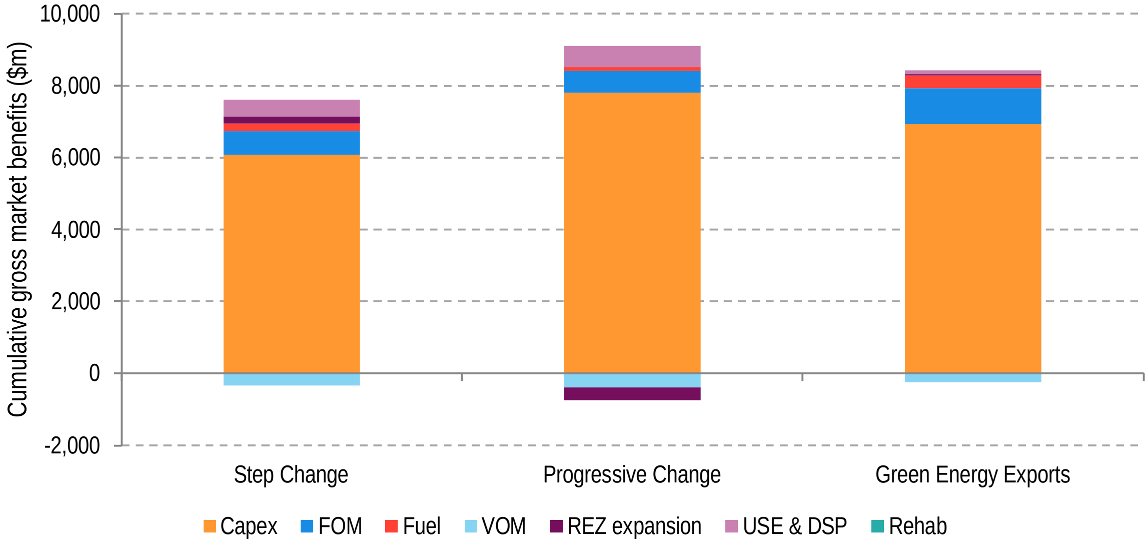
HumeLink Option	HumeLink Option timing	Step Change	Progressive Change	Green Energy Exports
Option 1C-new	1 July 2028	5,219	7,178	6,003
Option 2C	1 July 2028	7,101	7,987	7,811
Option 3C	1 July 2026	7,254	8,359	8,179

The forecast gross market benefits of each scenario must be compared to the cost of the HumeLink options to determine the forecast net economic benefit for each 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 the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.[1]

In all scenarios, the forecast benefits for HumeLink are primarily driven by capex saving across the NEM, followed by FOM cost saving as the second highest source of forecast benefit, as displayed in Figure 1 for Option 3C. Benefits for other options of HumeLink have a similar composition of market benefits.

[8] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *Cost benefit analysis guidelines*, and "net economic benefit" in the same manner defined in the guidelines.

Figure 1: Composition of forecast total gross market benefits of HumeLink; discounted to 1 July 2023 in millions of real June 2023 dollar terms[9]



The forecast capex and FOM savings associated with HumeLink are predominantly driven by supporting more cost-efficient investment in renewables and storage to meet emissions abatement and renewable energy policies as per the Draft 2024 ISP assumptions, including the recently instated federal target of 82% renewable energy by 2029-30. The fast pace of transition to renewable energy across all scenarios as a result of these policies causes HumeLink to be highly utilised. It improves connections in and surrounding the SWNSW area to South Australia (via EnergyConnect), Victoria (via VNI West), the Sydney load centre and Snowy 2.0. These connections allow HumeLink to capitalise on generation and load diversity between NEM regions and reduce build of PHES, storage, and gas.

This transition is forecast to occur fastest in the Green Energy Exports scenario, but the interplay between renewable energy targets and assumed demand outlook also influences the relative magnitude of forecast gross market benefits across the three scenarios.

Forecast gross market benefits of HumeLink are highest in the Progressive Change scenario despite this scenario having the slowest forecast transition to renewables of the three scenarios (although coal-fired generator retirements are still accelerated relative to announced retirement dates, as sourced from the Draft 2024 ISP and similar to the Step Change scenario to 2030). The high forecast gross market benefits are 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 renewable energy targets, which are the same across other scenarios as per the Draft 2024 ISP input assumptions. With demand reductions and fixed coal closure dates (based on the Draft ISP 2024 outcomes), the remaining coal capacity in the 2020s - which must run at minimum load when available – leaves little to no headroom for increased coal or gas operation at times of low availability of wind and solar while achieving the assumed 82% renewable energy target. To meet demand while satisfying the target without HumeLink, more costly renewables are installed over gas generation. This leads to higher benefits when some of those costs are avoided with HumeLink.

The Green Energy Exports scenario is forecast to have the next highest gross market benefits for HumeLink. As per the Draft 2024 ISP assumptions, electricity consumption in the NEM increases significantly over the modelling period in this scenario due to an assumed increase in electricity

[9] The material change in circumstance assessment has market benefit categories which includes the categories in this report as follows: avoided generation and storage costs (excluding fuel costs) = (capex, FOM, VOM), avoided fuel costs = fuel, avoided REZ transmission costs = REZ expansion, avoided unserved energy = USE, avoided voluntary load curtailment = DSP.

demand for hydrogen production. By the early 2030s, assumed demand in the NEM is more than four-fold higher than current annual consumption. Due to the large amount of new capacity required to meet this assumed demand and a more stringent carbon budget, more renewables and storage are subsequently required. Scenarios with a faster transition to renewable energy and storage are associated with greater utilisation of transmission between Wagga Wagga, Maragle and Bannaby, and greater opportunity for HumeLink to be utilised so as to reduce the needed investment in renewable energy, storage, and gas-fired generation whilst still adhering to all limits and constraints and meeting all targets. This leads to higher cost savings when capacity build is avoided.

As this transition to renewable energy is also forecast to occur rapidly in the Step Change scenario, forecast gross market benefits in this scenario are also significant.

2. Introduction

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 to New South Wales demand centres. The proposed network augmentation, would comprise around 365 km of additional 500 kV transmission lines and supporting equipment, connecting the greater Sydney load centre with the Snowy Mountains Hydroelectric Scheme (enabling the full 2,040 MW dispatch capacity of Snowy 2.0) and Project EnergyConnect in South-West New South Wales.

This Report forms a supplementary report to Transgrid's analysis, prepared and published by Transgrid. [1] It describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. This Report is accompanied by market modelling workbooks which contain summaries of key outcomes.

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 on policies, costs and generator technical parameters, as well as demand projections from AEMO in the 2023 IASR[10] and assumed timing of major transmission upgrades and coal-fired generator retirement dates based on the Draft 2024 ISP inputs and outcomes of the Optimal Development Path (ODP)[11]. Updates were included to reflect new market information from the AEMO Generation Information data as of September 2023[12]. The model also includes a 660 MW limit on Snowy 2.0 operation in the absence of HumeLink in line with the 2023 IASR.[10] 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 and involuntary load curtailment,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model,
- retirement/rehabilitation costs to cover decommissioning, demolition and site rehabilitation.

Each category of gross market benefits is computed across the 25-year Modelling Period, from 2024-25 to 2048-49. Benefits presented are discounted to 1 July 2023 using a 7% real, pre-tax

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[10] AEMO, December 2023, *2023 IASR Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024.

[11] AEMO, 15 December 2023 Draft *2024 ISP.* Available at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024.

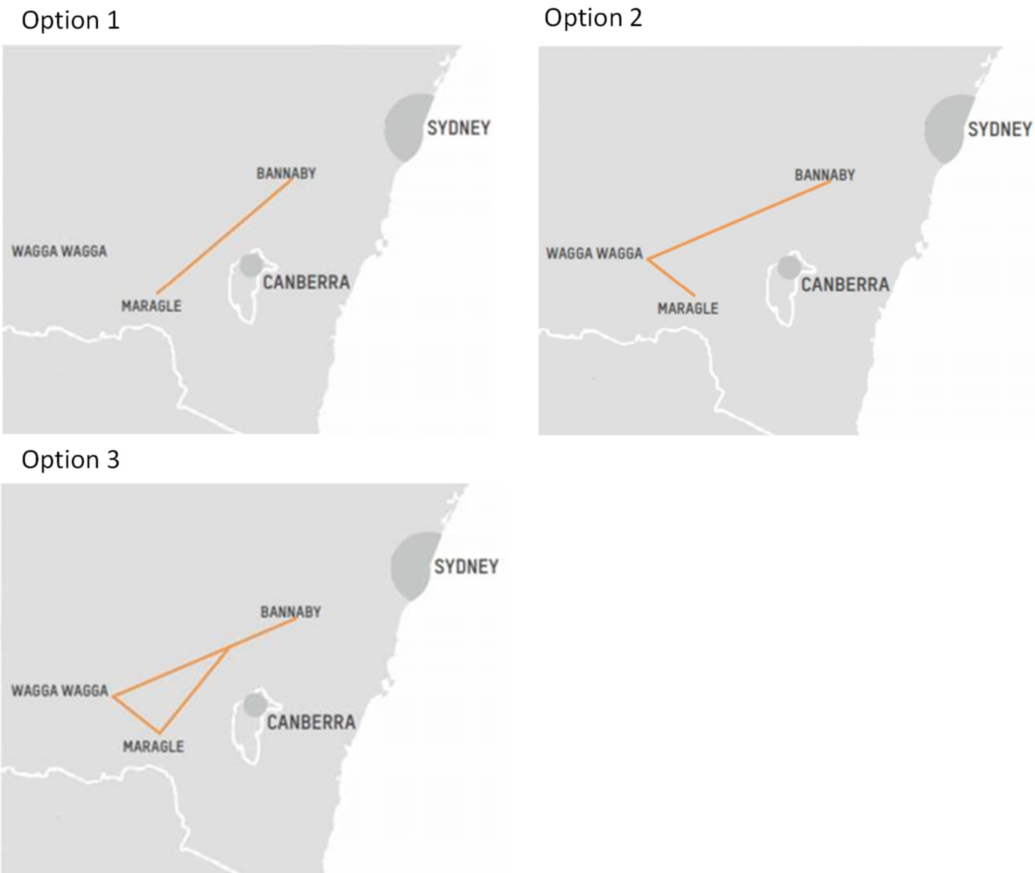
[12] AEMO, 28 September, NEM Generation Information Sep 2023. *Available at:* https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2023/nem-generation-information-sep-2023.xlsx. Accessed 1 February 2024

[13] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 1 February 2024.

discount rate, consistent with the central value applied by AEMO in the 2023 IASR[14]. This is higher than the discount rate applied in previous HumeLink studies for the RIT-T as discussed further in Section 6.

This modelling considers three different HumeLink augmentation topologies as defined by Transgrid and detailed in the PACR[15]. Option 3C is assumed to be commissioned by 1 July 2026 with Options 1C-new and 2C commissioned by 1 July 2028, as defined by Transgrid. Figure 2 presents a high-level visualisation of the three different HumeLink transmission augmentation topologies which were modelled for a construction and operation voltage of 500 kV. The differences between the options relate to the number of transmission lines, their configuration, their circuit thermal ratings and the assumed transmission access to the South-West NSW and Wagga Wagga REZs, as defined by Transgrid.

Figure 2: Overview of the HumeLink transmission augmentation topologies considered in this modelling[15]



The forecast gross market benefits of each scenario must be compared to the cost of the HumeLink options to determine the forecast net economic benefit for each 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 the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.[1]

The Report is structured as follows:

► Section 3 describes the input assumptions and scenarios modelled in this study.

[14] AEMO, December 2023, *2023 IASR Assumptions Workbook v5.3.* Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 7 February 2024.

[15] Transgrid, 29 July 2021, *Transgrid HumeLink PACR*. Available at: https://www.transgrid.com.au/projects-innovation/humelink. Accessed 7 February 2024.

- Section 4 presents the NEM capacity and generation outlook without HumeLink for the three scenarios.
- Section 5 presents the forecast gross market benefits associated with HumeLink. It is focussed on identifying and explaining the key sources of forecast gross market benefits for Option 3C, the preferred HumeLink option for all scenarios as determined by Transgrid.
- 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.

3. Scenario assumptions

3.1 Overview of input assumptions

HumeLink gross market benefits have been assessed under the Step Change, Progressive Change and Green Energy Exports scenarios as chosen by the Client in accordance with the CBA guidelines[6]. The modelling combines input assumptions on policies, costs, generator technical parameters and demand projections from the AEMO 2023 IASR[16] and assumed timing of major transmission upgrades and coal-fired generator retirement outcomes based on the Draft 2024 ISP inputs and outcomes of the ODP[18]. Where transmission investment timing in the ODP was earlier than the 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 2. All input assumptions were selected by the Client in accordance with the CBA guidelines.[6]

Table 2: 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)[17] – Step Change	2023 ESOO[17] – Progressive Change	2023 ESOO[17] – Green Energy Exports
Committed and anticipated generation	Committed and anticipated generators from AEMO's Generation Information September 2023[12]		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2023 IASR Assumptions Workbook[16] – Step Change	2023 IASR Assumptions Workbook[16] – Progressive Change	2023 IASR Assumptions Workbook[16] – Green Energy Exports
Retirements of coal-fired power stations	2024 Draft ISP Results Workbook[18] – Step Change ODP (Candidate Development Path 11) In line with closure year outcomes.	2024 Draft ISP Results Workbook[18] – Progressive Change ODP (Candidate Development Path 11) In line with closure year outcomes.	2024 Draft ISP Results Workbook[18] – Green Energy Exports ODP (Candidate Development Path 11) In line with closure year outcomes.
Gas fuel price	2023 IASR Assumptions Workbook[16] – Step Change	2023 IASR Assumptions Workbook[16] – Progressive Change	2023 IASR Assumptions Workbook[16] – Green Energy Exports
Coal fuel price	2023 IASR Assumptions Workbook[16] – Step Change	2023 IASR Assumptions Workbook[16] – Progressive Change	2023 IASR Assumptions Workbook[16] – Green Energy Exports
NEM carbon budget to achieve Federal Government's 2030 emissions reduction target	2023 Inputs and Assumptions Workbook v5.3[16]: 630 Mt CO2-e 2024-25 to 2029-30		
NEM carbon budget to achieve 2050 temperature-linked emissions levels	2024 Draft ISP Results Workbook[18] – Step Change: 664 mega ton (Mt) CO_2-e 2024-25 to 2048-49	2024 Draft ISP Results Workbook[18] – Progressive Change: 890 Mt CO_2-e 2024-25 to 2048-49	2024 Draft ISP Results Workbook[18] – Green Energy Exports: 355 Mt CO_2-e 2024-25 to 2048-49

[16] AEMO, December 2023, *2023 IASR Assumptions Workbook v5.3*: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024.

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

[18] AEMO, December 2023, Draft 2024 ISP results workbook: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 7 February 2024

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Federal Government Renewable Energy Target	2023 IASR Assumptions Workbook v5.3[16]: 82% share of renewable generation by 2029-30		
Victoria Renewable Energy Target (VRET)	Victoria Renewable Energy Target (VRET) – 40% by 2025, 65% by 2030 and 95% by 2035 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 Consistent with 2023 IASR Assumptions Workbook v5.3[16]		
Queensland Renewable Energy Target (QRET)	50% by 2029-30, 70% by 2031-32 and 80% by 2034-35 renewable generation as a percentage of total Queensland demand Consistent with 2023 IASR Assumptions Workbook v5.3[16]		
Tasmanian Renewable Energy Target (TRET)	15,750 GWh by 2030 and 21,000 GWh by 2040 Consistent with 2023 IASR Assumptions Workbook v5.3[16]		
NSW Electricity Infrastructure Roadmap	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. Consistent with 2023 IASR Assumptions Workbook v5.3[16]		
Victorian SIPS	150 MW import capability in VNI link after VIC SIPS contract ends 31 March 2032 consistent with 2023 IASR Assumptions Workbook v5.3[16]		
Waratah Super Battery SIPS	2023 IASR Assumptions Workbook v5.3[16]: 250 MW increase in export capacity from July 2025 ending July 2030		
EnergyConnect	2023 IASR Assumptions Workbook v5.3[16]: commissioned by July 2026		
Western Renewables Link	2023 IASR Assumptions Workbook v5.3[16]: commissioned by July 2027		
HumeLink	HumeLink commissioned by 1 July 2026 in Option 3C and commissioned by 1 July 2028 in Options 2C and 3C as per client assumption shown in Table 3.		
New-England REZ Transmission	Earliest in-service date advised by proponent[18]: ► New England REZ Transmission Link 1 commissioned by September 2028 Draft 2024 ISP outcome[18] – Step Change: ► New England REZ Upgrade commissioned by July 2030 ► New England Transmission Link 2 commissioned by July 2034	Draft 2024 ISP outcome[18] – Progressive Change: ► New England REZ Transmission Link1 commissioned by July 2031 ► New England REZ Upgrade commissioned by July 2031 ► New England Transmission Link 2 commissioned by July 2042	Earliest in-service date advised by proponent[18]: ► New England REZ Transmission Link 1 commissioned by September 2028 Draft 2024 ISP outcome[18] – Green Energy Exports: ► New England REZ Upgrade commissioned by July 2030 ► New England Transmission Link 2 commissioned by July 2032
Central-West Orana REZ Transmission Link	Earliest in-service date advised by proponent[18]: commissioned by August 2028	Earliest in-service date advised by proponent[18]: commissioned by August 2028	Earliest in-service date advised by proponent[18]: commissioned by August 2028
Project Marinus Stage 1	Earliest in-service date advised by proponent[18]: commissioned by July 2030		
Project Marinus Stage 2	Draft 2024 ISP outcome[18] –Step Change: 2nd cable commissioned by July 2036	Draft 2024 ISP outcome[18]– Progressive Change: 2nd cable commissioned by July 2036	Earliest in-service date advised by proponent[18]: commissioned by December 2032

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Queensland-New South Wales interconnector (QNI) Connect	Draft 2024 ISP – Step change outcome[18]: commissioned by July 2033	Draft 2024 ISP – Progressive Change outcome[18]: commissioned by July 2036	Draft 2024 ISP – Green Energy Exports outcome[18]: commissioned by July 2030 and stage 2 to be commissioned by July 2044
CopperString 2032	2023 IASR Assumptions Workbook v5.3[16]: commissioned by June 2029		
Victoria-New South Wales Interconnector (VNI) West	Earliest in-service date advised by proponent[18]: commissioned by December 2029	Draft 2024 ISP – Progressive Change outcome[18]: commissioned by July 2034	Draft 2024 ISP – Green Energy Exports outcome[18]: commissioned by July 2031
Snowy 2.0	Commissioned by December 2028 Snowy 2.0 dispatch level for both pumping and generation is constrained to 660 MW without HumeLink commissioned, consistent with the 2023 IASR Assumptions Workbook v5.3[16].		
Discount rate	7% real, pre-tax[16]		

3.2 Differences in assumptions with and without HumeLink

Across all scenarios, the differences between the options relative to each other and the Base Case relate to the number of transmission lines, their configuration, their circuit thermal ratings and the assumed transmission access to the South-West NSW and Wagga Wagga REZs, as defined by Transgrid. Key input assumptions are summarised in Table 3.

Table 3 Modelled transmission differences between the Base Case and each HumeLink option, supplied by Transgrid

Cut-set/link	Cut-set definition and limits			
	Base Case	Option 1C-new	Option 2C	Option 3C
HumeLink commissioning date	n/a	1 July 2028	1 July 2028	1 July 2026
Snowy cut-set	Lower Tumut- Canberra Upper-Tumut-Canberra Lower Tumut-Yass Upper Tumut-Yass			
	2,870 MW	2,980 MW	3,080 MW	3,080 MW
Snowy + HumeLink cut-set	As above	As above Maragle-Bannaby_O1C	As above Maragle-Wagga_O2C	As above Maragle-Bannaby_O3C Maragle-Wagga_O3C
	2,870 MW	5,920 MW	5,230 MW	5,372 MW

Cut-set/link	Cut-set definition and limits			
	Base Case	Option 1C-new	Option 2C	Option 3C
Canberra/Yass-Bannaby cut-set	Yass-Bannaby Canberra-Bannaby	Yass-Bannaby Canberra-Bannaby Maragle-Bannaby_O1C	Yass-Bannaby Canberra-Bannaby Wagga-Bannaby_O2C	Yass-Bannaby Canberra-Bannaby Maragle-Bannaby_O3C Wagga-Bannaby_O3C
	2,700 MW	5,330 MW	5,230 MW	4,900 MW
Bannaby-NCEN	3,100 MW Post WSB SIPS project 3,350 MW[19]	4,500 MW Post WSB SIPS project 4,750 MW	4,500 MW Post WSB SIPS project 4,750 MW	4,500 MW Post WSB SIPS project 4,750 MW
Wagga-SWNSW	1,700 MW export 1,500 MW import	2,700 MW export 3,000 MW import	2,700 MW export 3,000 MW import	2,700 MW export 3,000 MW import
SWNSW REZ free transmission limit	1,000 MW (with PEC)	1,000 MW (with PEC)	1,800 MW (with PEC) 2,700 MW (with PEC+VNI West)	1,800 MW (with PEC) 2,700 MW (with PEC+VNI West)
Wagga Wagga REZ free transmission limit	1,100 MW	1,100 MW	2,600 MW	2,600 MW

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

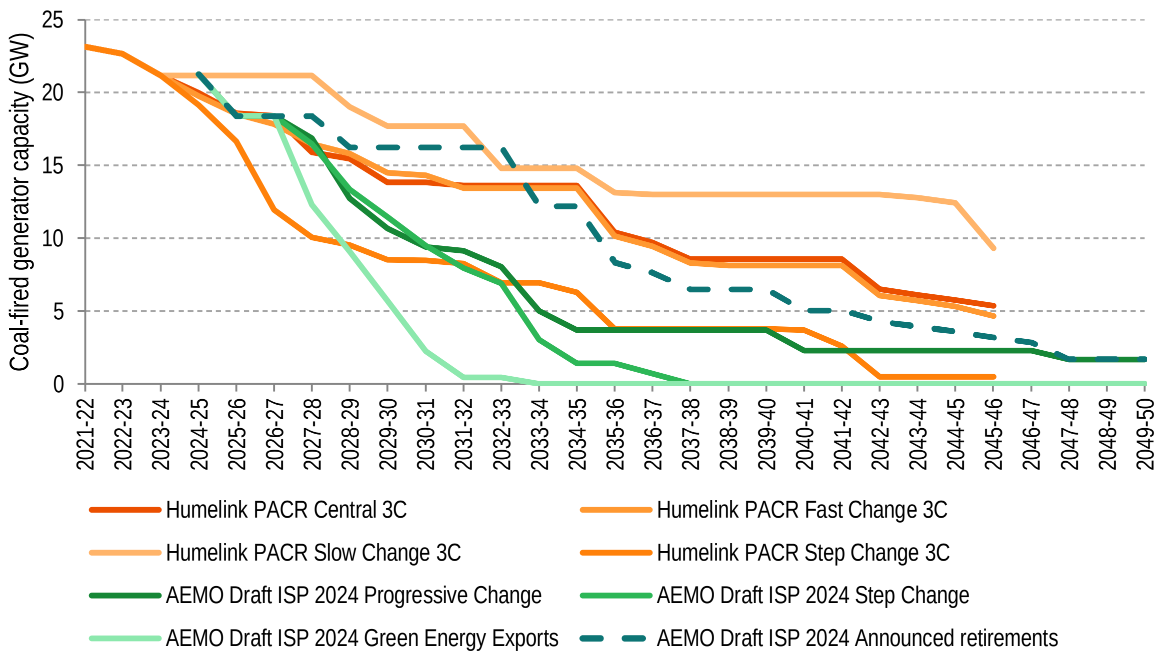
4. Forecast NEM outlook in the without HumeLink case

Before presenting the forecast benefits of the 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 without HumeLink.

4.1 Forecast coal-fired power plant withdrawal

Based on the scenario settings described in Section 3, and in line with the 2024 ISP methodology, thermal retirements are determined on a least-cost basis. Coal-fired generator retirement dates are assumed to occur at or earlier than their end-of-technical-life or announced retirement year according to the Draft 2024 ISP outcomes for the respective scenarios. This is illustrated in Figure 3. The announced retirement schedules for coal units in this figure are based on the AEMO Generating Unit Expected Closure Year – September 2023.[20] Figure 3 also shows the coal-fired generator retirement outcomes from the HumeLink PACR modelling[21] for comparison. It is evident that the Draft 2024 ISP scenarios incorporate a faster withdrawal of coal capacity relative to all HumeLink PACR scenarios except the HumeLink PACR Step Change scenario.

Figure 3: Forecast coal-fired generator capacity in the NEM by year across all scenarios in the without HumeLink cases[22]



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, renewable energy targets (federal, 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 Draft ISP 2024 model forecasts the entire coal capacity withdraws by the early 2030s in the Green Energy Exports scenario, while this is closer to 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until just prior to the end of the Modelling Period.

[20] AEMO, Generating Unit Expected Closure Year – September 2023. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2023/generating-unit-expected-closure-year.xlsx?la=en. Accessed 1 February 2024

[21] Transgrid, 29 July 2021, *Transgrid HumeLink PACR*. Available at: https://www.transgrid.com.au/projects-innovation/humelink. Accessed 7 February 2024.

[22] In the model 2,880 MW from the four units of Eraring retires in August 2025 (after the beginning of the 2025-26 financial year).

4.2 Forecast NEM capacity and generation outlook

The NEM-wide capacity mix forecast in the Step Change scenario without HumeLink is shown in Figure 4 and the corresponding generation mix in Figure 5. In this scenario, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas. This outcome is broadly consistent with the Draft 2024 ISP outcomes for this scenario, noting that the Draft 2024 ISP does not model an equivalent Base Case.

Figure 4: NEM capacity mix forecast for the Step Change scenario without HumeLink[23]

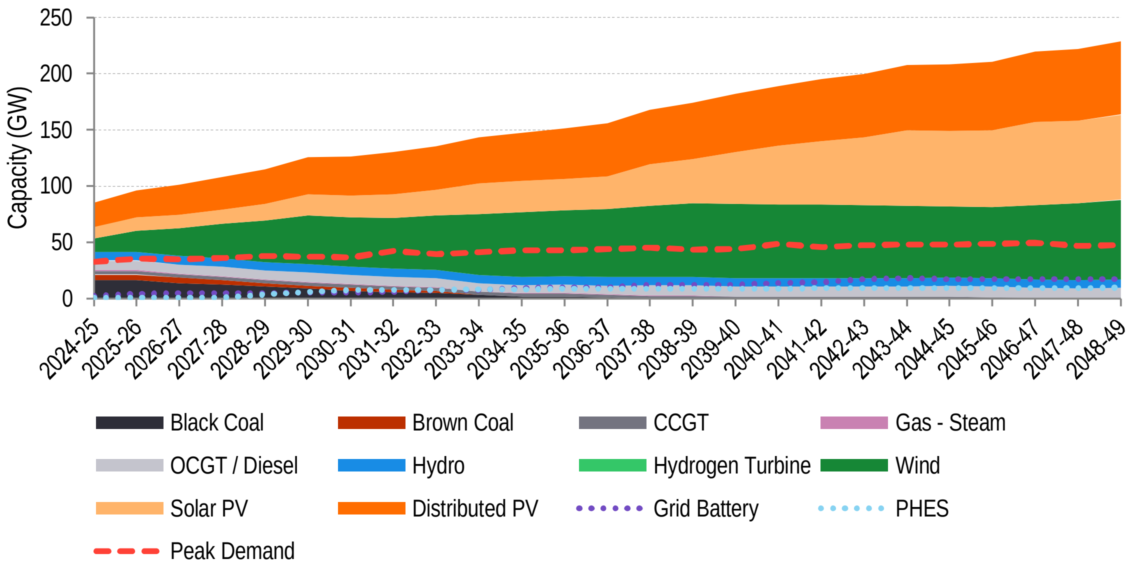
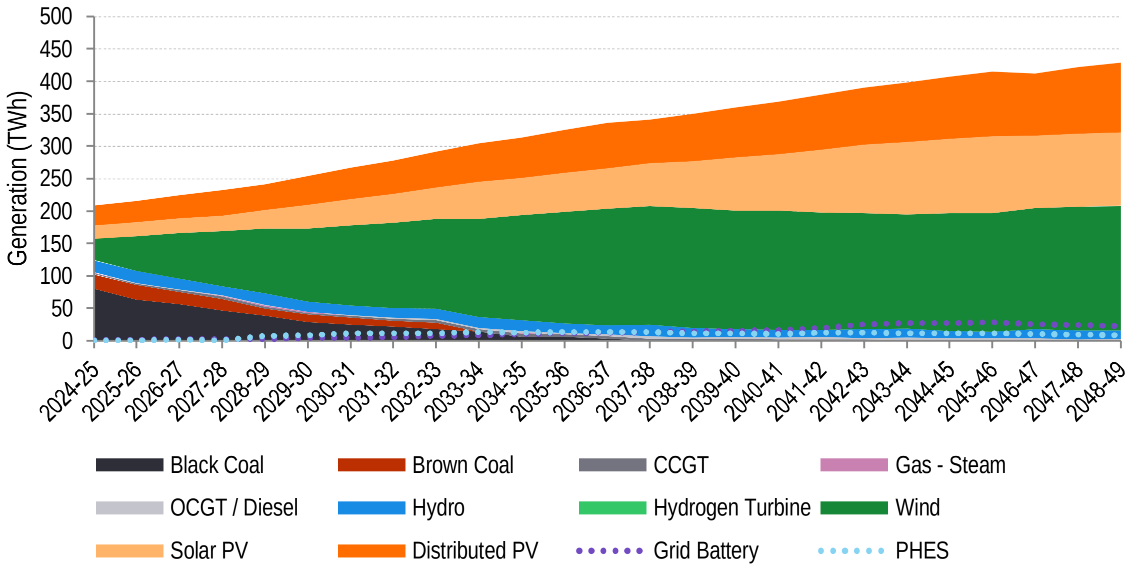


Figure 5: NEM generation mix forecast for the Step Change scenario without HumeLink



Up to 2030, new wind and solar build is largely driven by the assumed federal renewable energy target. During this period, the federal renewable energy policy 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 battery and pumped hydro storage capacity in line with the assumed state-based storage targets,

[23] Dispatchable battery includes both large-scale battery and VPP.

with Snowy 2.0 (which is assumed to be committed in accordance with the Draft 2024 ISP) forming a significant part of the pumped hydro 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 also supports reserve requirements. Overall, the NEM is forecast to have roughly 256 GW total (generation and storage) capacity by 2048-49, 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 6 and Figure 8 show the differences in the NEM capacity development of the other two scenarios relative to the Step Change scenario, while Figure 7 and Figure 9 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario (e.g. Figure 6 shows Progressive Change scenario capacity minus Step Change scenario capacity; a net 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 6 and Figure 7 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 Draft 2024 ISP.

Figure 6: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios without HumeLink

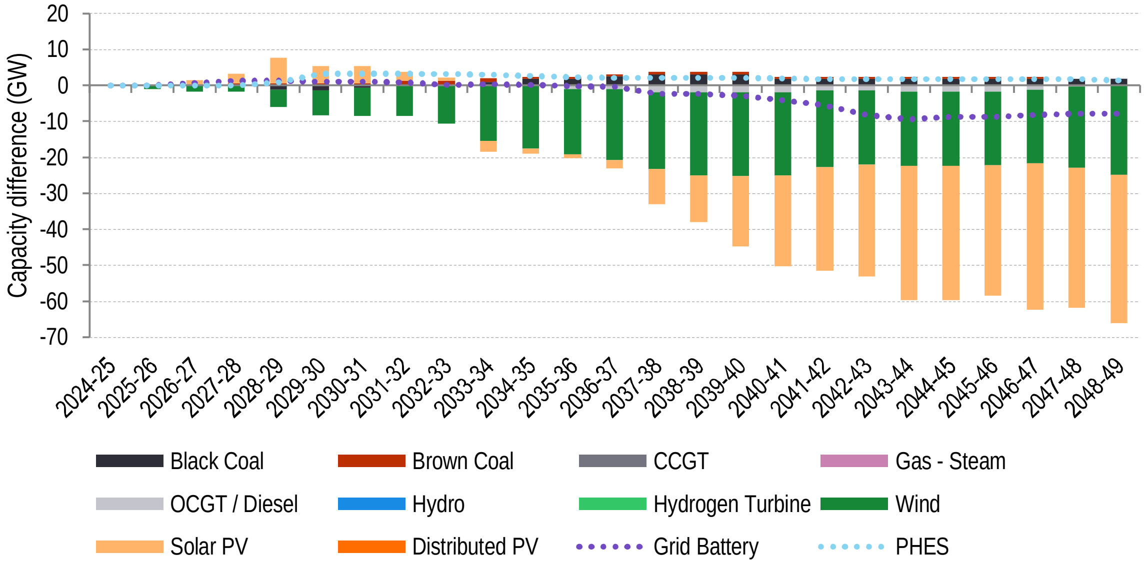


Figure 7: Difference in NEM generation forecast between the Progressive Change and Step Change scenarios without HumeLink

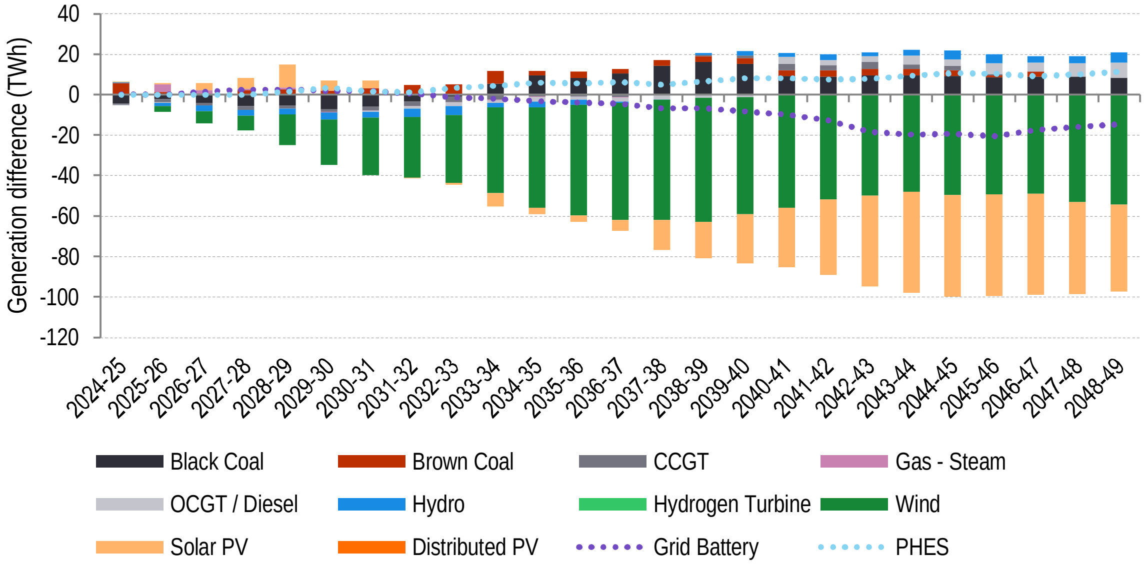


Figure 8 and Figure 9 show that the Green Energy Exports scenario is forecast to withdraw coal generation and install wind and solar generation more rapidly than the Step Change scenario due to different assumptions such as the more restrictive carbon budget and higher demand outlook, as defined by the Draft 2024 ISP.

Figure 8: Difference in NEM capacity forecast between the Green Energy Exports and Step Change scenarios without HumeLink

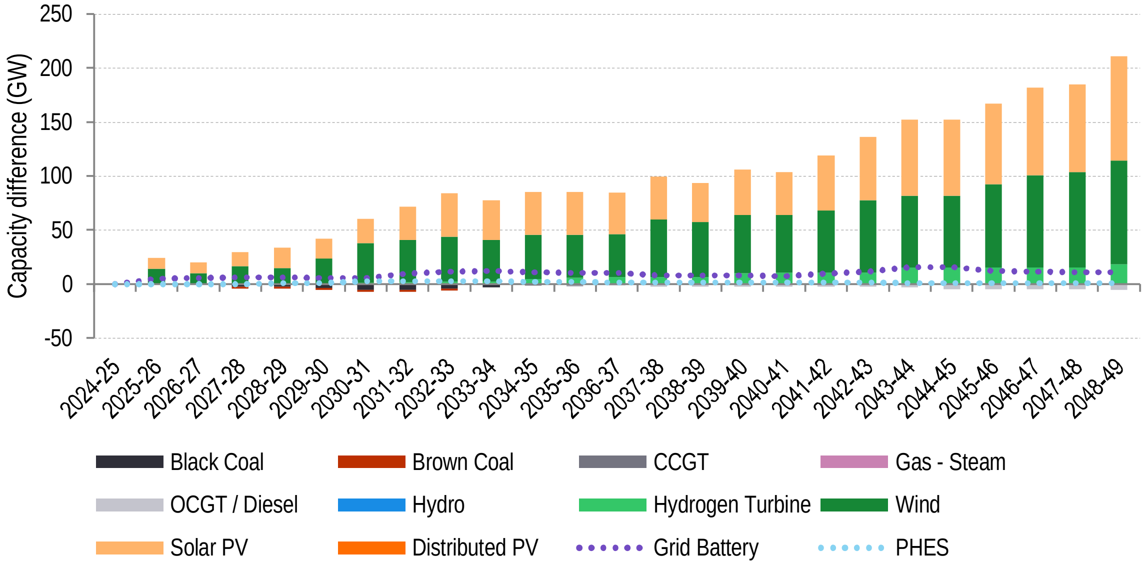
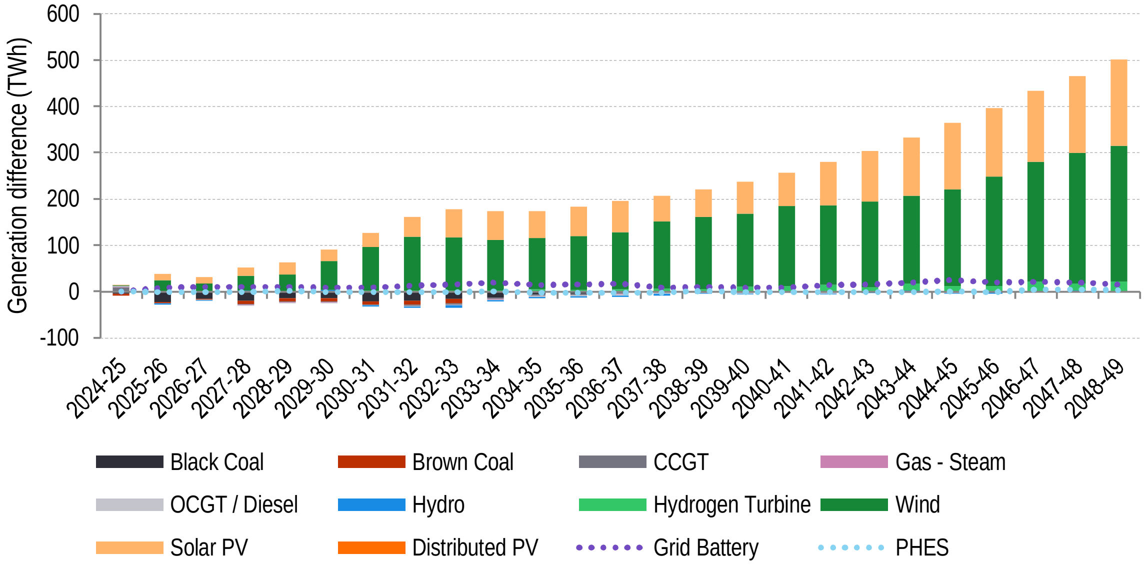


Figure 9: Difference in NEM generation forecast between the Green Energy Exports and Step Change scenarios without HumeLink



5. Forecast gross market benefit outcomes

5.1 Summary of forecast gross market benefit outcomes across scenarios

Table 4 shows the forecast gross market benefits of HumeLink over the 25-year Modelling Period from 2024-25 to 2048-49 for the Step Change, Progressive Change and Green Energy Exports scenarios.

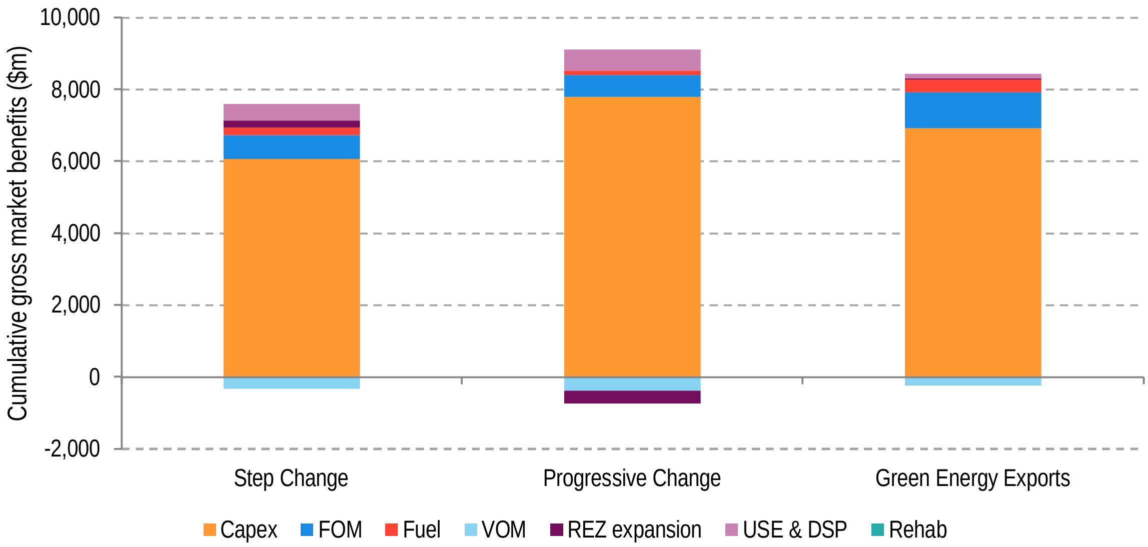
Table 4: Overview of scenarios with associated forecast gross market benefits for Marinus Link; discounted to 1 July 2023 in millions of real June 2023 dollar terms

HumeLink Option	HumeLink Option timing	Step Change	Progressive Change	Green Energy Exports
Option 1C-new	1 July 2028	5,219	7,178	6,003
Option 2C	1 July 2028	7,101	7,987	7,811
Option 3C	1 July 2026	7,254	8,359	8,179

The forecast gross market benefits of each scenario must be compared to the cost of the HumeLink options to determine the forecast net economic benefit for each 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 the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.[1]

In all scenarios, the forecast benefits for HumeLink are primarily driven by capex saving across the NEM, followed by FOM cost saving as the second highest source of forecast benefit, as displayed in Figure 10 for Option 3C. Benefits for other options of HumeLink have a similar composition of market benefits.

Figure 10: Composition of forecast total gross market benefits of HumeLink Option 3C across options; discounted to 1 July 2023 in millions of real June 2023 dollar terms



The forecast capex associated with HumeLink are predominantly driven by supporting more cost-efficient investment in renewables to meet emissions abatement and renewable energy policies as per the Draft 2024 ISP assumptions, including the federal 82% renewable energy by 2029-30 target. The fast pace of transition to renewable energy across all scenarios allows HumeLink to be highly utilised by improving connections in and surrounding the SWNSW area to the rest of the

NEM, which includes improving connections between the greater Sydney load centre, Snowy 2.0 and Project EnergyConnect.

Additionally, HumeLink reduces build of PHES, storage and gas through providing better access to Snowy 2.0 to fully unlock its potential and enabling the flow of power to capitalise on generation and load diversity between NEM regions.

The Progressive Change scenario is forecast to have higher benefits for HumeLink compared to the Step Change scenario despite it having the slowest forecast transition to renewables of the three scenarios (although coal-fired generator retirements are still accelerated relative to announced retirement dates, as sourced from the Draft 2024 ISP and similar to the Step Change scenario to 2030). The high forecast gross market benefits are 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 renewable energy targets, which are the same across other scenarios as per the Draft 2024 ISP input assumptions. With demand reductions and fixed coal closure dates (based on the Draft ISP 2024 outcomes), the remaining coal capacity in the 2020s - which must run at minimum load when available – leaves little to no headroom for increased coal or gas operation at times of low availability of wind and solar while achieving the assumed 82% renewable energy target. To meet demand while satisfying the target without HumeLink, more costly renewables are installed over gas generation. This leads to higher benefits when some of those costs are avoided with HumeLink.

The Green Energy Exports scenario is also forecast to have a high gross market benefit for HumeLink. As per the Draft 2024 ISP assumptions, electricity consumption in the NEM increases significantly over the modelling period in this scenario due to an assumed increase in electricity demand for hydrogen production. By the early 2030s, assumed demand in the NEM is more than four-fold higher than current annual consumption as shown in Figure 28. Due to the large amount of new capacity required to meet this assumed demand and a more stringent carbon budget, more renewables and storage are subsequently required. Scenarios with a faster transition to renewable energy and storage are associated with greater utilisation of transmission between Wagga Wagga, Maragle and Bannaby, and greater opportunity for HumeLink to be utilised to avoid investment in renewable energy, storage, and gas-fired generation. This leads to higher cost savings when capacity build is avoided.

In the remainder of this section:

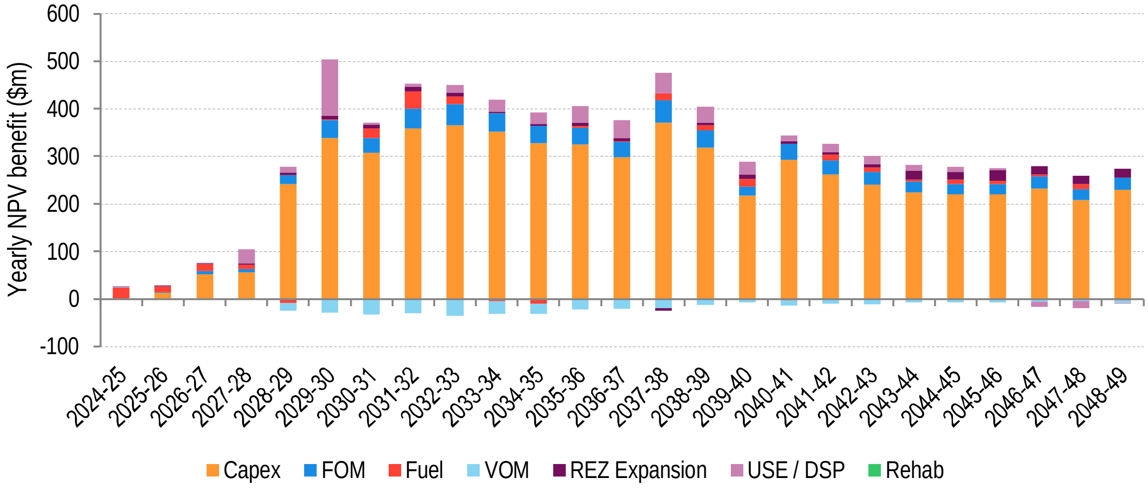
- ► Sections 5.2 to 5.4 describe the market dynamics for each of the three scenarios with HumeLink Option 3C, commissioned in 2026-27.
- ► Section 5.5 outlines differences in forecast outcomes with different options of HumeLink.

5.2 Market modelling outcomes for Option 3C Step Change scenario

5.2.1 Forecast gross market benefits, Step Change scenario

The gross market benefits forecast for HumeLink Option 3C with commissioning in 2026-27 in the Step Change scenario are depicted in Figure 11 on an annual, discounted basis. Over the Modelling Period, it is forecast that the inclusion of HumeLink results in $7,254m in gross market benefits discounted to 1 July 2023 (in real June 2023 dollar terms).

Figure 11: Annual HumeLink market benefit forecast for the Step Change scenario in the NEM, HumeLink Option 3C; discounted to 1 July 2023 in millions of real June 2023 dollar terms



Market benefits due to HumeLink are predominantly forecast to occur after 2028-29 which is when Snowy 2.0 is commissioned in December 2028, However, a small quantity of forecast benefits accrue prior to HumeLink's assumed commissioning in 2026-27 due to small pre-emptive differences in the least-cost generation outlook forecast in a model with perfect foresight.

Most of the benefit of HumeLink is forecast to be from the reduction in expected capex costs, followed by lower savings from FOM and USE/DSP.

- Capex savings are due to the reduced investment in renewables and storage (battery and pumped hydro) facilitated by HumeLink strengthening the network around South-West NSW and unlocking Snowy 2.0 generation to its full dispatch capacity.
- DSP occurs when there is insufficient supply to meet demand at a particular moment in time, for instance when there are natural resource droughts. This is forecast to occur in 2029 when there are wind droughts across Central-West Orana and nearby REZ's and the market benefit from DSP is noticeably higher in this year. This insufficient generator and storage supply is due to the 82% renewable energy target preventing of gas and coal-fired dispatch. It is determined to be cheaper to dispatch DSP than build additional wind, solar or storage capacity in this period. The sharing of energy through HumeLink allows dispatch of DSP to reduce.

5.2.2 Forecast NEM generation development plan, Step Change scenario

The differences in the forecast capacity and generation outlooks in Step Change scenario across the NEM with and without HumeLink Option 3C are shown in Figure 12 and Figure 13, respectively.

Figure 12: Forecast capacity difference with and without HumeLink Option 3C, commissioned 2026-27 for the Step Change scenario

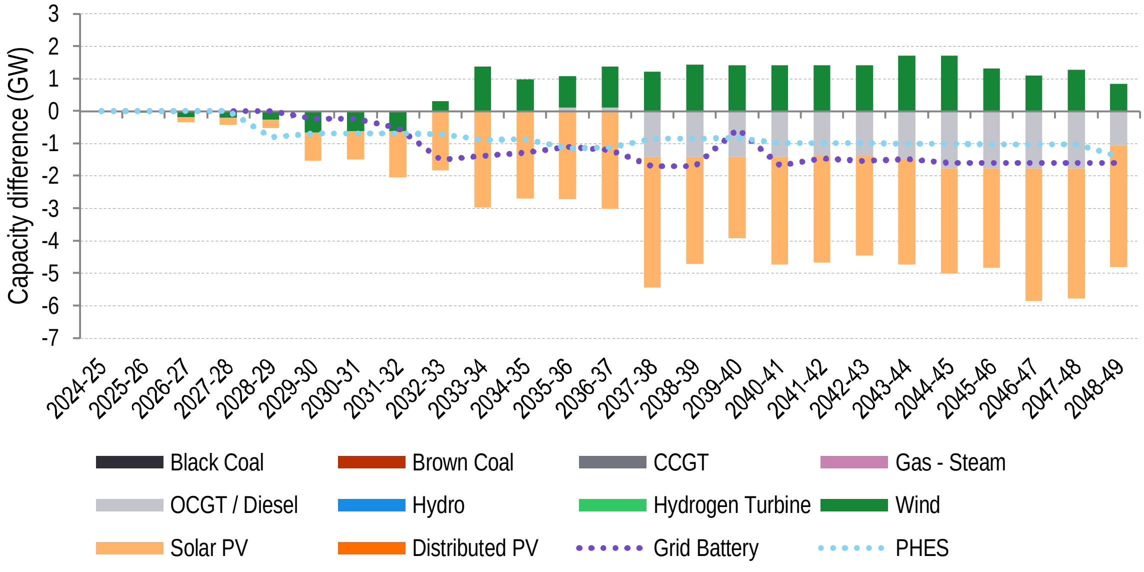


Figure 13: Forecast generation difference with and without HumeLink Option 3C, commissioned 2026-27 for the Step Change scenario

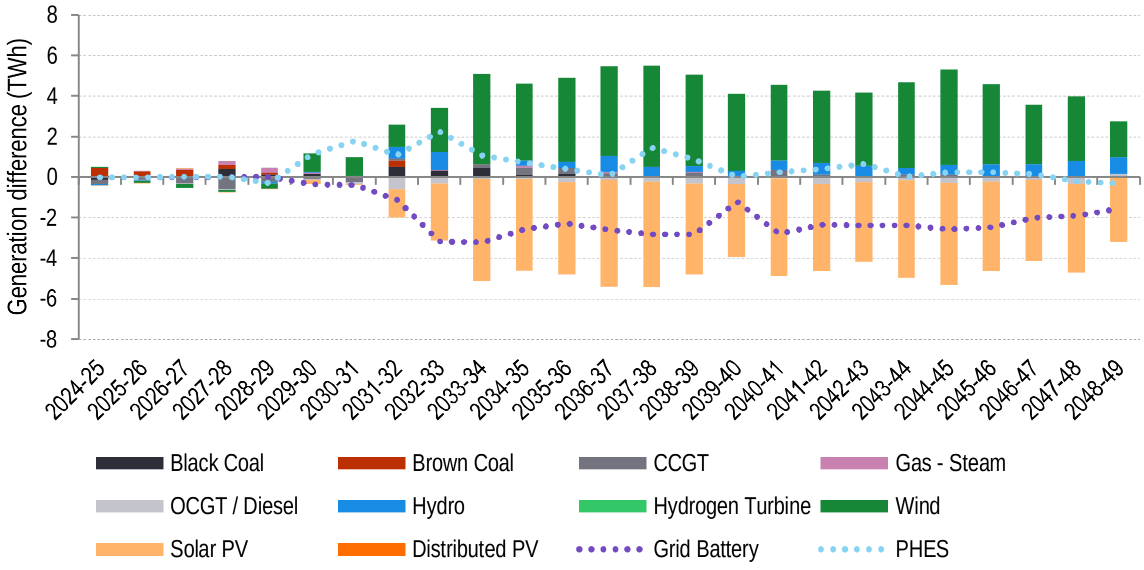


Figure 12 shows that solar, large-scale battery storage, pumped hydro and gas capacity across the NEM are forecast to be avoided, and replaced with wind capacity with the inclusion of HumeLink. With greater shared energy, as well as the increased storage capacity in Snowy 2.0, alternative types of storage build, both short and long duration are avoided, and it becomes more efficient to build wind capacity than solar.

Figure 13 shows that the amount of forecast wind generation increase is at a similar volume to the forecast solar generation decrease, despite the replacement wind capacity being less than the solar capacity in the Base Case as seen in Figure 12. This replacement wind capacity with HumeLink is able to achieve a higher capacity factor than the solar capacity in the Base Case. The amount of battery generation also decreases, while PHES dispatch increases despite the decrease in PHES build, due to the effect of HumeLink on fully unlocking Snowy 2.0 dispatch. There is a slight increase in coal-fired generation with HumeLink while still meeting the assumed emissions budget over the full 25-year modelling period. This is achieved because HumeLink is forecast to decrease reliance on gas generation in later years by improving generation sources. Overall, HumeLink is forecast to allow the NEM to achieve the assumed renewable energy and emissions targets at lower cost in the Step Change scenario.

The differences in capacity outlooks with and without HumeLink Option 3C in the Step Change scenario in REZs with notable differences are shown in Figure 14.

Figure 14: Modelled REZ capacity mix difference between HumeLink Option 3C and Base Case in the Step Change scenario

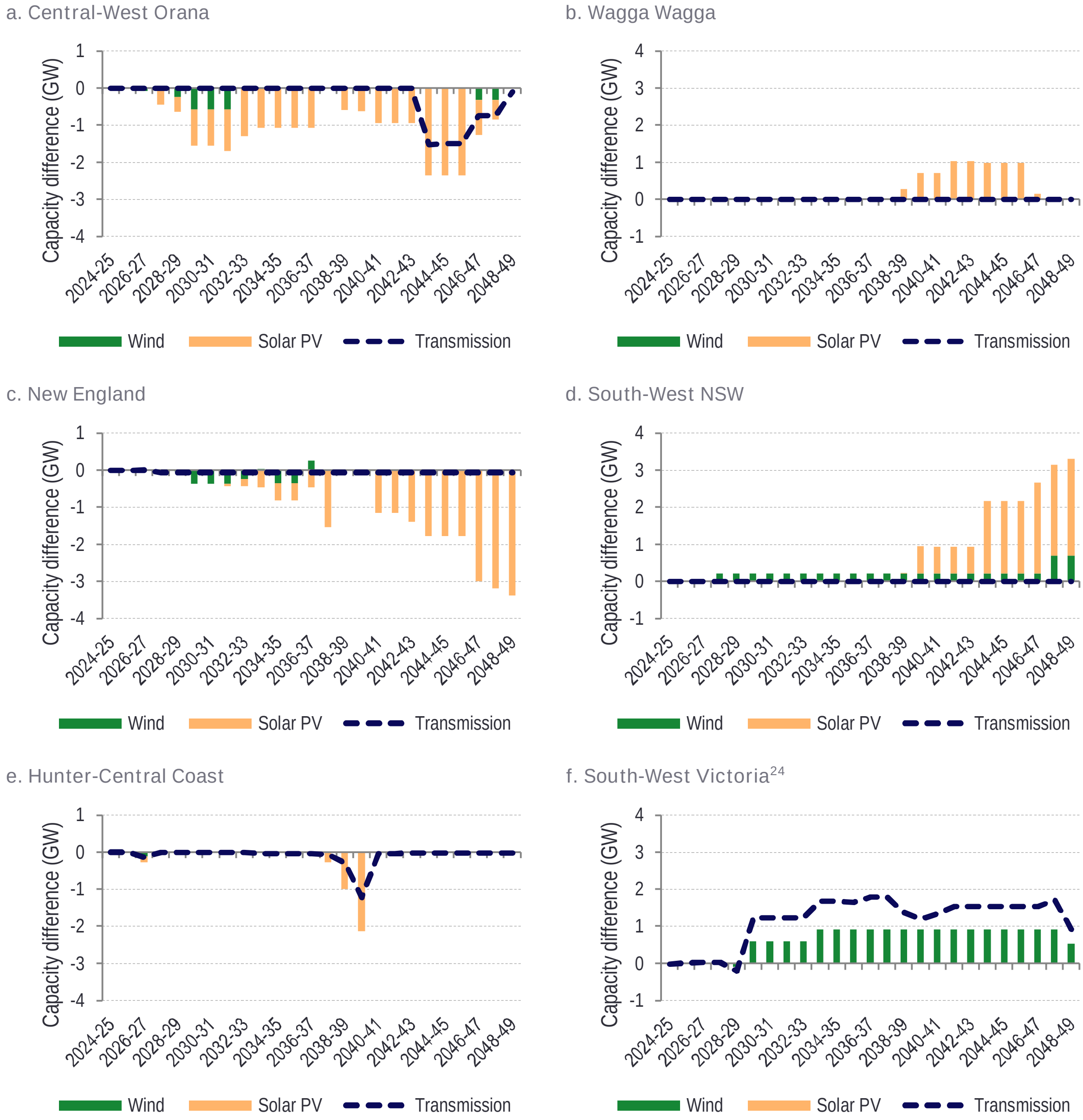


Figure 14 shows that HumeLink unlocks greater investment in wind and solar in South-West NSW, Wagga Wagga as well as South-West Victoria REZs, which offsets investment in Central-West Orana and New England REZs, which are the predominant REZ's in NSW, as well as less investment in Hunter-Central Coast. South-West NSW and Wagga Wagga REZs both have assumed transmission limit improvements with HumeLink. HumeLink therefore supports more cost-efficient investment in renewables, enabling more low-cost capacity build away from the main regions of investment in

[24] South-West Victoria transmission represents transmission built to satisfy the SWV1 group constraint which also includes generation from Portland Coast REZ and dispatch of the Heywood interconnector.

Central-West Orana and New England, as well as enabling more higher capacity factor wind capacity build in Victoria through the improved connection via VNI West.

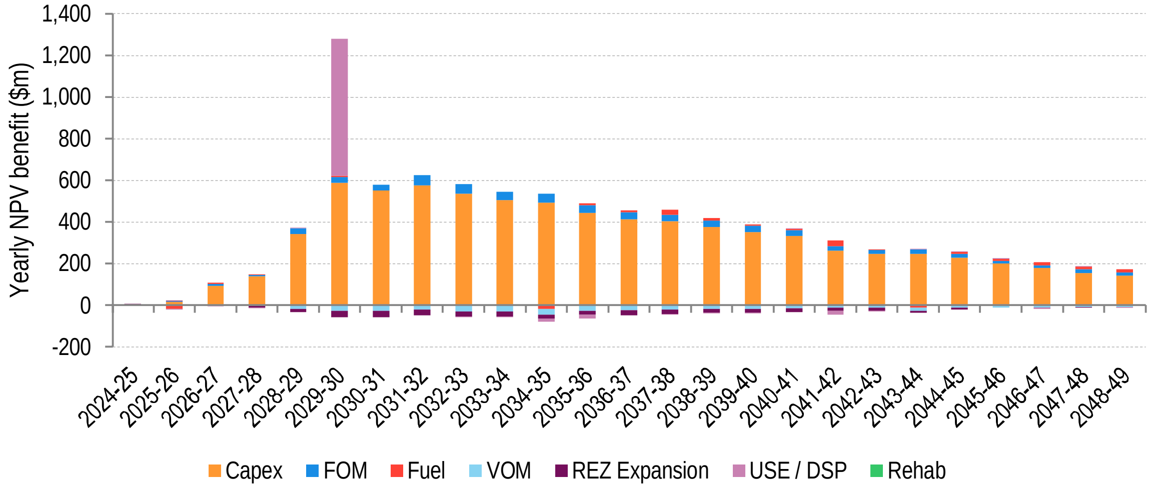
HumeLink Option 3C provides additional direct transmission access to the Wagga Wagga (+1,500 MW) and South-West NSW REZs (+1,700 MW). However, it is not part of the least-cost development path to build additional wind or solar to use this additional REZ transmission capacity immediately or in full in the case of Wagga Wagga REZ. Instead, it is lower cost to build some additional wind capacity in Victoria and use the improved connection through VNI West to Sydney to transport power from Victoria and offset build in NSW. The assumed average capacity factors for high/medium wind in South-West Victoria REZ are 39%/38% compared to 29%/29% in South-West NSW REZ and 27%/26% in Wagga Wagga REZ).[2]

5.3 Market modelling outcomes for Option 3C Progressive Change scenario

5.3.1 Forecast gross market benefits, Progressive Change scenario

The gross market benefit forecast for HumeLink Option 3C with commissioning in 2026-27 in the Progressive Change scenario are depicted in Figure 15 on an annual, discounted basis. Over the Modelling Period, it is forecast that the inclusion of HumeLink results in $8,359m in gross market benefits discounted to 1 July 2023 (in real June 2023 dollar terms).

Figure 15: Annual market benefit forecast for Progressive Change scenario, HumeLink Option 3C; discounted to 1 July 2023 in millions of real June 2023 dollar terms



As in the Step Change scenario, annual benefits of HumeLink are forecast to accrue once HumeLink is commissioned in 2026-27. Differences in the forecast capacity and generation outlook result in minor negative benefits in 2025-26, the year before commissioning, due to small pre-emptive differences in the least-cost generation outlook forecast in a model with perfect foresight.

The Progressive Change scenario is forecast to have higher benefits for HumeLink compared to the Step Change scenario for the reasons explained in Section 5.1. The 82% federal renewable target, emissions budget to 2050 and VRET 95% renewables target are all binding constraints within the modelling for this scenario, indicating that these targets are impacting capacity investment and dispatch outcomes. Meeting these targets with reduced demand in the 2020s and coal retirement dates based on Draft 2024 ISP outcomes gives greater opportunity for HumeLink to reduce investment in wind, solar and storage that is required but not heavily utilised in the Base Case.

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 lower savings from FOM and USE/DSP. The same effect on DSP benefits in 2029-30 observed in the Step Change scenario also occurs here, albeit to a much larger extent. In the Progressive Change scenario in particular, gas and coal-fired generation cannot be used during this period as doing so would mean not meeting the renewable energy policy targets, leaving a gap in supply. DSP dispatch occurs as it is determined that it is cheaper than to build additional wind, solar or storage capacity that isn't heavily utilised in other weather years when renewable energy has higher availability. The sharing of energy through HumeLink allows dispatch of DSP to reduce, although it is still non-zero in the HumeLink case. In conjunction with the later assumed transmission project timings, and large demand retirements in 2029-30 the avoided DSP is particularly high for Progressive Change.

5.3.2 Forecast NEM generation development plan, Progressive Change scenario

The differences in the forecast capacity and generation outlooks in Progressive Change scenario across the NEM with and without HumeLink Option 3C, commissioned 2026-27 are shown in Figure 16 and Figure 17, respectively.

Figure 16: Capacity difference with and without HumeLink Option 3C, commissioned 2026-27 for the Progressive Change scenario

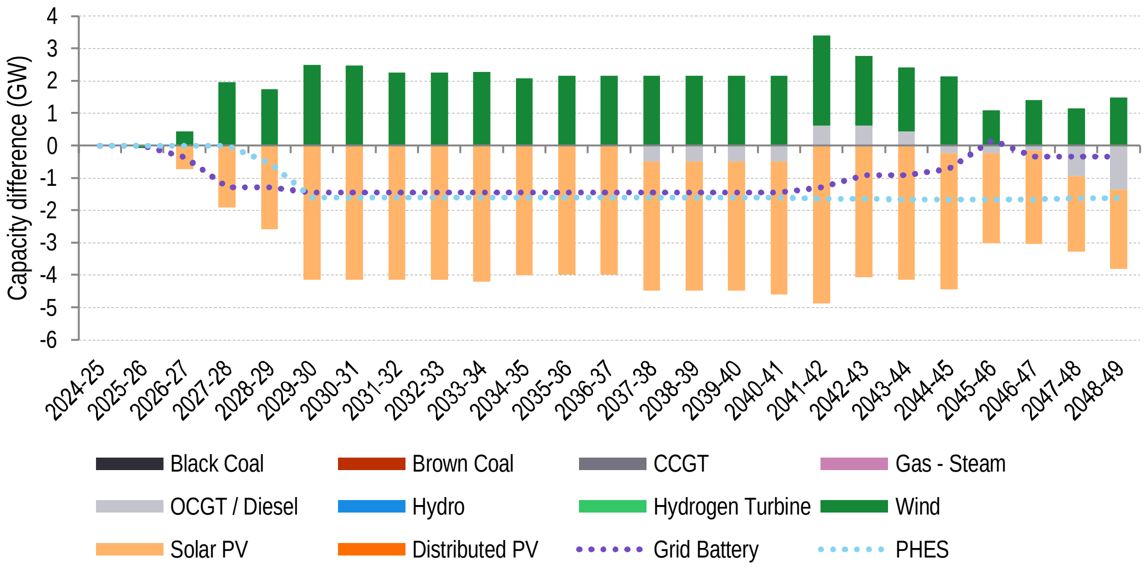


Figure 17: Generation difference with and without HumeLink Option 3C, commissioned 2026-27 for the Progressive Change scenario

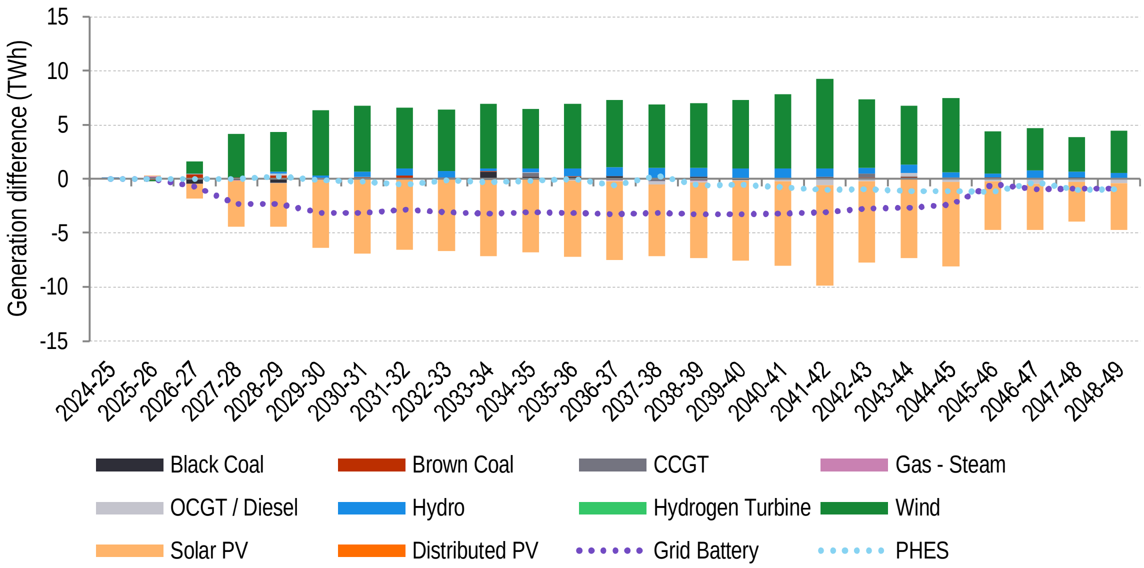
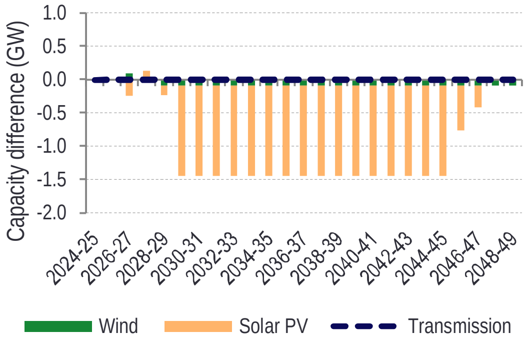


Figure 16 and Figure 17 show that investment in new wind and solar PV is forecast to be avoided from 2026-27 when HumeLink is assumed to be commissioned. Similar to the Step Change scenario, wind capacity build increase is less than solar build decrease, while wind generation increase is greater than solar generation decreases the wind capacity is more efficient than the solar capacity in the Base Case. Battery and pumped hydro capacity also decrease, due to the effect of HumeLink on unlocking Snowy 2.0 dispatch, displacing storage capacity from the Base Case. This is achieved because HumeLink is forecast to decrease reliance on gas generation by improving generation sources and better connecting major generation centres. HumeLink is forecast to allow the NEM to achieve the assumed renewable energy and emissions targets at lower cost in the Progressive Change scenario.

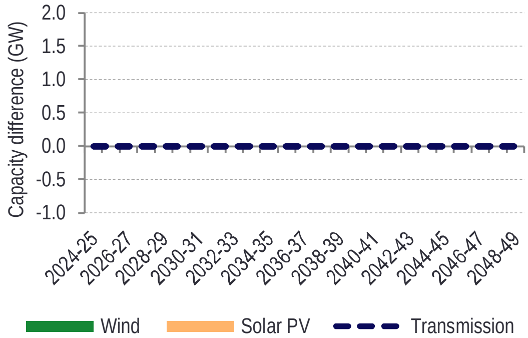
The differences in capacity with and without HumeLink Option 3C in the Progressive Change scenario in REZs with notable differences are shown in Figure 18.

Figure 18: Modelled REZ capacity mix difference between Option 3C and Base Case in Progressive Change

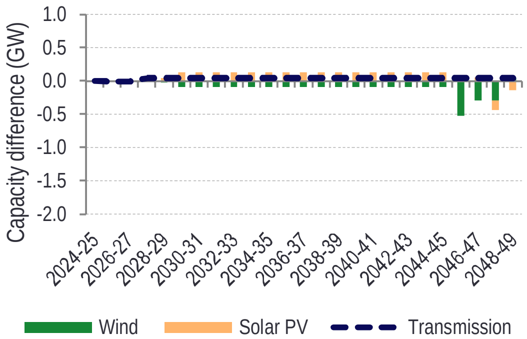
a. Central-West Orana



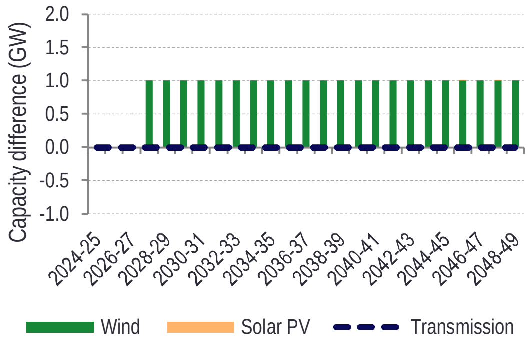
b. Wagga Wagga



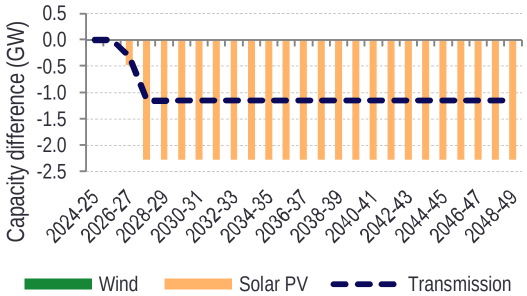
c. New England



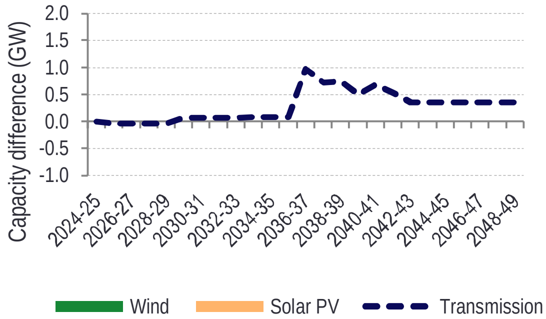
d. South-West NSW



e. Hunter-Central Coast



f. South-West Victoria[25]



Similar to the Step Change scenario, Figure 18 with HumeLink, there is less investment in Central-West Orana and New England REZs, while there is greater investment in South-West NSW REZ. In

[25] South-West Victoria transmission represents transmission built to satisfy the SWV1 group constraint which also includes generation from Portland Coast REZ and dispatch of the Heywood interconnector.

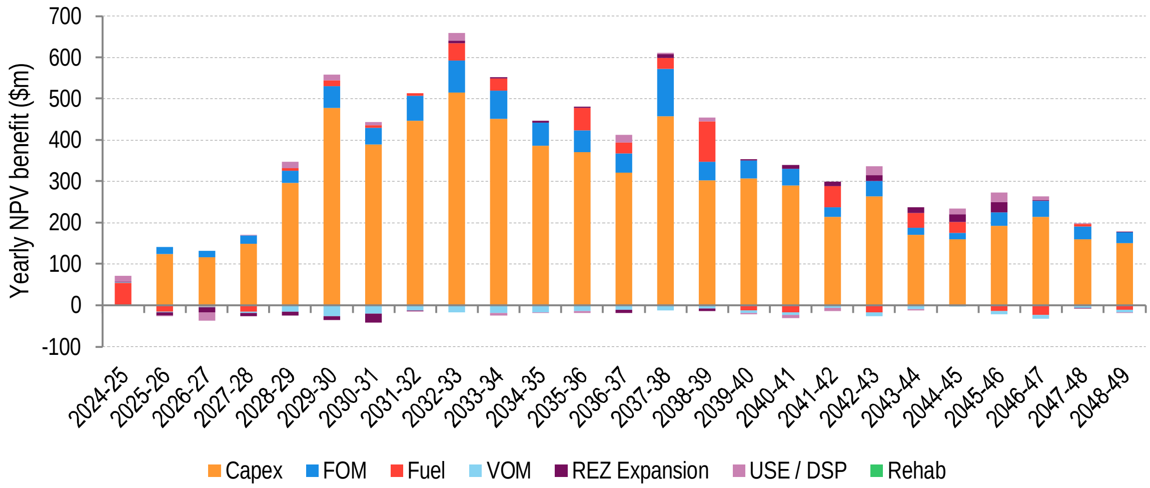
contrast to the Step Change scenario there is negligible change in renewable build in Wagga Wagga and South-West Victoria REZs and less avoided build in Central-West Orana and New England REZs, while there is more avoided build in Hunter-Central Coast REZ. Additionally, replacement build in South-West NSW REZ consists of wind rather than solar, and at a smaller capacity. This reflects the lower overall capacity build due to lower demand.

5.4 Market modelling outcomes for Option 3C Green Energy Exports scenario

5.4.1 Forecast gross market benefits, Green Energy Exports scenario

The gross market benefits forecast for HumeLink Option 3C, commissioned 2026-27 in the Green Energy Exports scenario are depicted in Figure 19 on an annual, discounted basis. Over the Modelling Period, it is forecast that the inclusion of HumeLink will result in $8,179m in gross market benefits discounted to 1 July 2023 (in real June 2023 dollar terms).

Figure 19: Annual market benefit forecast for Green Energy Exports scenario, HumeLink Option 3C; discounted to 1 July 2023 in millions of real June 2023 dollar terms



The Green Energy Exports scenario is forecast to have higher benefits for HumeLink compared to the Step Change scenario for the reasons explained in Section 5.1. This scenario is forecast to have more fuel cost savings from the 2030s than the Step Change scenario, due to the effect of HumeLink unlocking Snowy 2.0 dispatch capability and these fuel cost savings are inclusive of hydrogen as a fuel source.

Gross benefits also accrue in years prior to HumeLink commissioning assumed in 2026-27. The capex savings are driven by a deferral in project expenditure in anticipation of HumeLink commissioning. Fuel savings in 2024-25 are driven by foreknowledge that HumeLink increases renewable support between major states once commissioned. This provides additional headroom in the long-term emissions budget (which is a binding constraint in the model), meaning higher emission but lower cost fuels can generate earlier in place of lower emission, higher cost fuels (gas-fired generation) in 2024-25 to minimise system cost as these emissions are offset later so that the emissions budget is still met.

5.4.2 Forecast NEM generation development plan, Green Energy Exports scenario

The differences in the forecast capacity and generation outlooks in Green Energy Exports scenario across the NEM with and without HumeLink are shown in Figure 20 and Figure 21, respectively. Throughout the Modelling Period, the primary source of forecast benefits of HumeLink is driven by the forecast reduction in new entrant installation across the NEM (Figure 20). With HumeLink, the

NEM is forecast to meet the assumed emission target with lower capacity build through more efficient utilisation of renewable sources with higher capacity factors and long duration storage provided by Snowy 2.0.

Figure 20: Capacity difference with and without HumeLink Option 3C, commissioned 2026-27 for the Green Energy Exports scenario

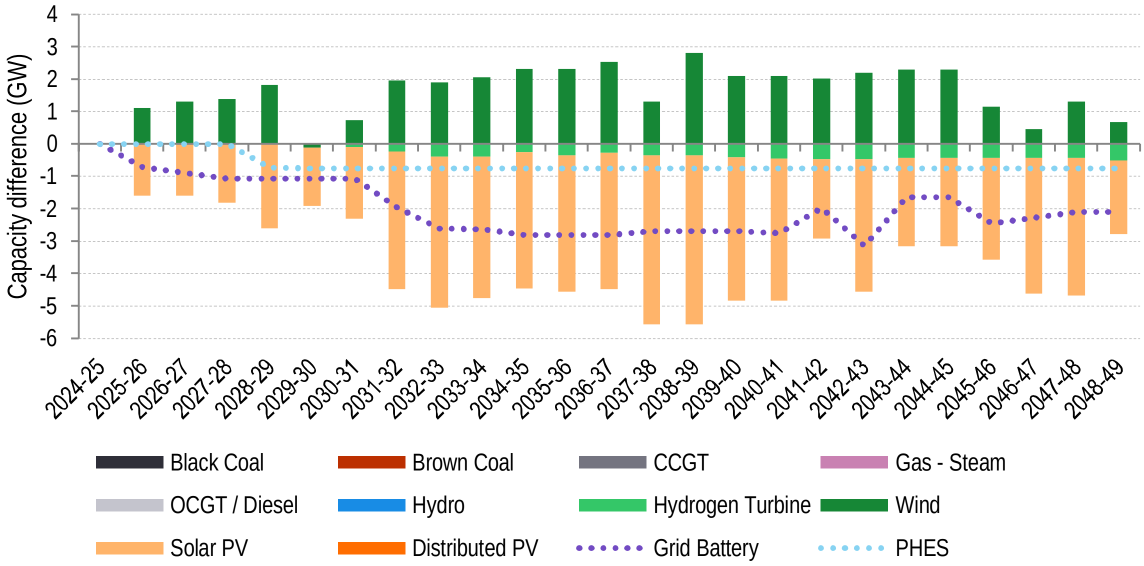


Figure 21: Generation difference with and without HumeLink Option 3C, commissioned 2026-27 for the Green Energy Exports scenario

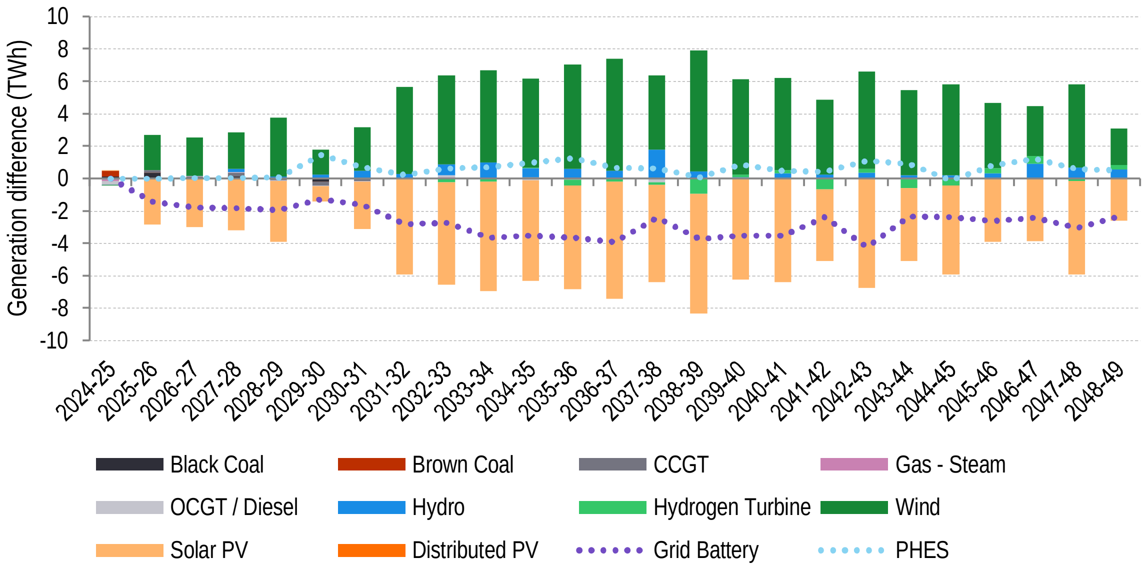


Figure 20 shows the forecast reduction in new entrant capacities is primarily a reduction in solar PV and battery storage, with some reduction in PHES investment and Hydrogen Turbines. Figure 21 shows that HumeLink is forecast to reduce solar operation across the NEM as a result of having better access to high capacity factor wind generation instead, through better connections around South-West NSW.

The differences in capacity with and without HumeLink Option 3C in the Green Energy Exports scenario in REZs with notable differences are shown in Figure 22.

Figure 22: Modelled REZ capacity mix difference between Option 3C and Base Case in Green Energy Exports

Similar to the Step Change scenario, Figure 22 shows that the effect of HumeLink is less investment in Central-West Orana and New England REZs, as well as less investment in Hunter-Central Coast REZ while there is greater investment in South-West NSW, Wagga Wagga as well as South-West Victoria REZs. Differences for the Green Energy Exports scenario are that there is additional wind built within these REZs, reflecting the large volume of capacity build in this scenario due to higher demand, as well as much higher land limits and therefore greater utilisation of REZs.

HumeLink is expected to support more cost-efficient investment in renewables, enabling more low-cost capacity build away from the main regions of investment in Central-West Orana and New England REZs, as well as enabling more higher capacity factor wind capacity build in Victoria through the improved connection along VNI West.

[26] South-West Victoria transmission represents transmission built to satisfy the SWV1 group constraint which also includes generation from Portland Coast REZ and dispatch of the Heywood interconnector.

5.5 Market modelling outcomes for the HumeLink option variants

This section presents the forecast market benefits for HumeLink across each scenario for the option variants, as outlined in Section 3.1. The commissioning dates for each option are as follows:

- Option 1C-new commissioned in 2028-29
- Option 2C commissioned in 2028-29
- Option 3C commissioned in 2026-27.

This Report considers only forecast gross market benefits of HumeLink. Given that the costs of the three options are expected to vary with the different configurations and commissioning dates (to reflect the more advanced planning and delivery status of Option 3C as advised by Transgrid), this must also be considered in any comparison between options. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. The calculation of net economic benefits and preferred option was conducted by the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.[1]

Figure 23, Figure 24 and Figure 25 display the forecast gross market benefits for the three options across each of the three scenarios.

Figure 23: Annual market benefit forecast for Step Change scenario across the three HumeLink options; discounted to 1 July 2023 in millions of real June 2023 dollar terms

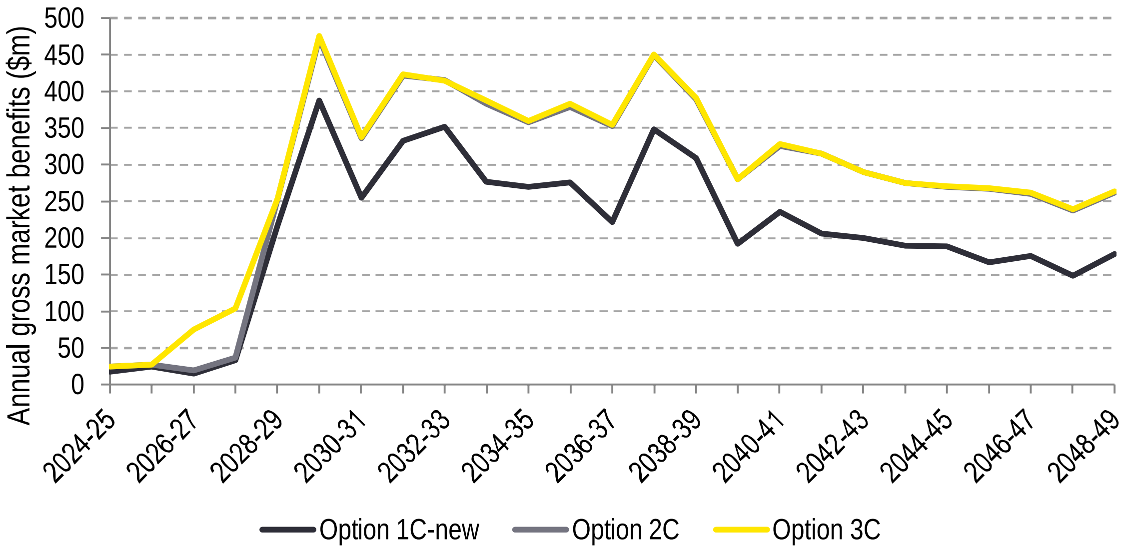


Figure 24: Annual market benefit forecast for Progressive Change scenario across the three HumeLink options; discounted to 1 July 2023 in millions of real June 2023 dollar terms

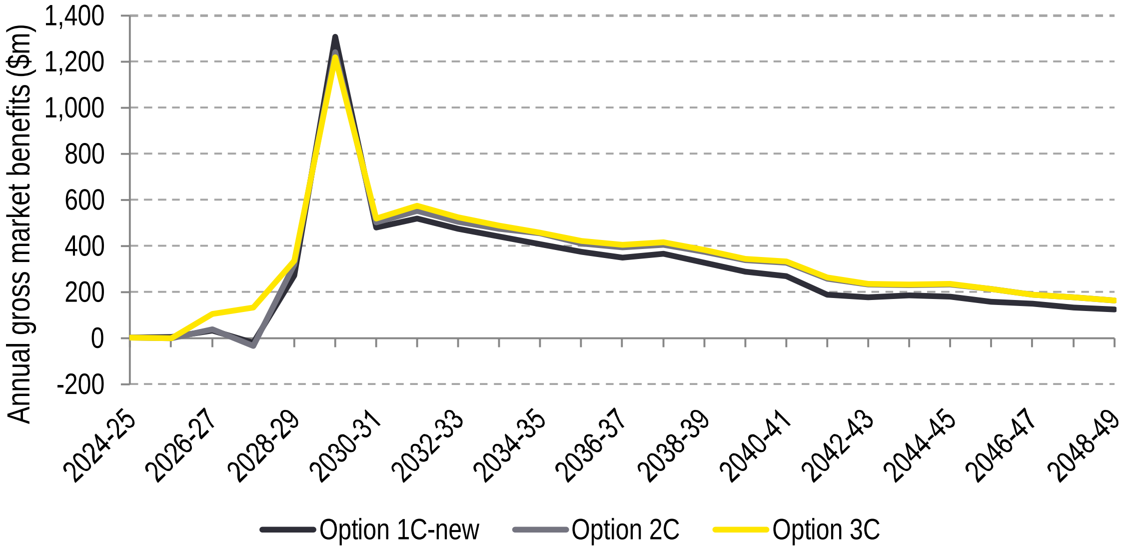
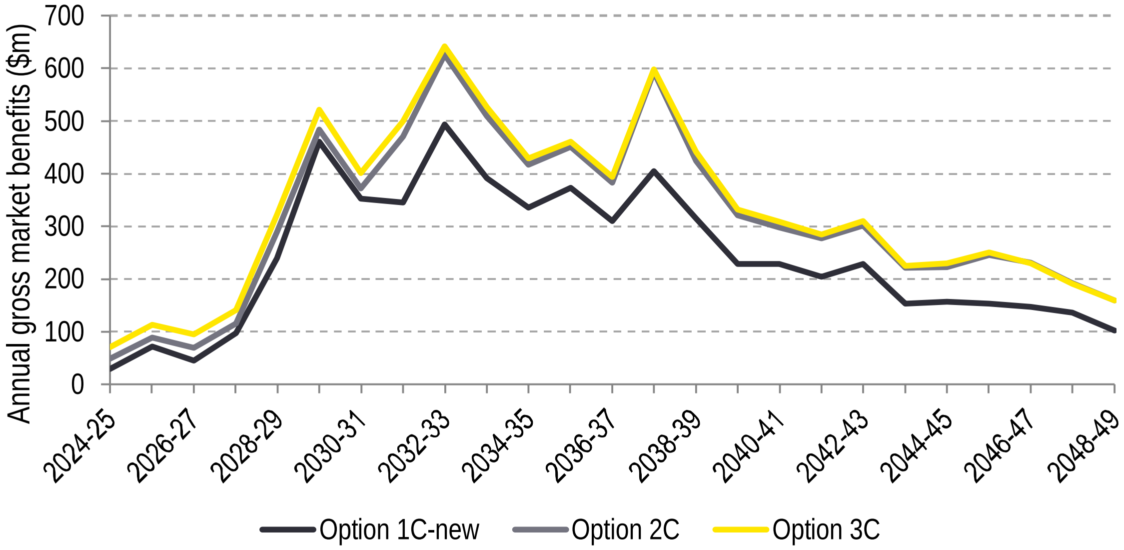


Figure 25: Annual market benefit forecast for Green Energy Exports scenario across the three HumeLink options; discounted to 1 July 2023 in millions of real June 2023 dollar terms



Across each scenario, Option 2C and Option 3C follow a similar trend in forecast annual gross market benefits. Due to the earlier commissioning of Option 3C, higher benefits compared to Option 2C are accrued in 2026-27 and 2027-28. This is most apparent in the Step Change and Progressive Change scenarios. In addition, the longer route for Option 2C and differences in limits on some cut-sets relative to Option 3C contribute to persistently lower forecast annual gross benefits. This is most apparent in the Green Energy Exports scenario as lines are most heavily utilised in this scenario.

Option 1C-new, while also sharing the same annual trend has lower benefits compared to Option 2C and 3C in most years, reflecting the lack of connection between Wagga Wagga and Maragle/Bannaby, and lack of connection to South-West NSW and Wagga Wagga REZs which is present in other HumeLink options. Option 1C-new does not integrate as fully with Project EnergyConnect and VNI West and does not unlock transmission access to renewables further west and south.

6. Comparison to HumeLink PACR July 2021 scenarios and outcomes

The previous assessment of gross market benefits of HumeLink was completed in the PACR which was published in July 2021.[13]

When comparing gross market benefit forecasts in the PACR and this Report, note that dollars, the date present values are discounted to and the discount rate applied differ:

- PACR real June 2019 dollars discounted to June 2021 using 5.9% discount rate
- Now real June 2023 dollars discounted to June 2023 using a 7% discount rate.

Conversion between the units is not possible as the discount rate is an input assumption that affects the simulation itself. However, changing from 2019 to 2023 dollars and removing two years of discounting will increase apparent benefits. Conversely increasing the discount rate will decrease apparent benefits.

Noting that a direct comparison of values is not possible, it is evident that the forecast gross market benefits of HumeLink have increased, relative to the PACR assessment. Key drivers of the increase in forecast gross market benefits relative to the PACR are the emissions and renewable energy policies in the scenario's modelled today based on policy commitments, and the Snowy 2.0 660 MW dispatch constraint before HumeLink commissioning. These assumptions are consistent with the Draft 2024 ISP.

The PACR modelled four scenarios that aligned key input assumptions with the 2020 ISP. The weighting of scenarios was also aligned with the 2020 ISP. The scenarios and associated weightings were: Central 40%, Fast Change 30%, Step Change 20% and Slow Change 10%.

Compared to the HumeLink PACR, emissions and renewable energy policies in the Draft 2024 ISP scenarios are much more ambitious. In the PACR, all scenarios had an emissions target of 26% reduction from 2005 levels by 2030. Only Step Change and Fast Change scenarios had further cumulative emissions budgets of 1,465 Mt and 2,208 Mt respectively for 2022-2050.

All three scenarios modelled for the current study have much more stringent carbon budgets to 2030 and 2052. The budget for 2025-2052 ranges from 357 Mt in Green Energy Exports to 681 Mt in Step Change to 1,203 Mt in Progressive Change. In terms of carbon abatement ambition, the slowest scenario modelled today is Progressive Change and the pace is only slightly lower than the PACR's most ambitious scenario. Renewable targets are also much more ambitious with policies assumed in all scenarios, as shown in Table 2, above what was assumed in the PACR.

The overall effect of these policies is the accelerated exit of coal-fired generators and an accelerated transition to renewable energy and storage relative to the PACR as seen in Figure 3. In all but the Step Change scenario, coal retirement dates are significantly advanced relative to the PACR. The PACR Central scenario, with the highest weighting at 40%, forecast 8.5 GW of coal online in 2039-40. In contrast, the scenarios in the current study forecast 0 GW remaining in the Step Change and Green Energy Exports scenarios and 3.7 GW in Progressive Change at the same point in time.

Scenarios with a faster transition to renewable energy and storage are associated with greater utilisation of transmission between Wagga Wagga, Maragle and Bannaby, and greater opportunity for HumeLink to be utilised to avoid investment in renewable energy, storage, and gas-fired generation. A reduction in forecast coal and gas fuel use in the scenarios presented in this Report relative to the PACR scenarios means there is reduced opportunity for HumeLink to deliver fuel cost savings. Savings associated with avoided and deferred capex are even more dominant.

Assumed demand outlook is another significant factor in setting the pace of transition. In the 2020 ISP scenarios which were used as the basis for the PACR, no scenarios considered hydrogen load within the NEM. In contrast, the Step Change and Green Energy Export scenarios in the current study both consider domestic and export hydrogen load. Demand due to this and other assumed loads means operational demand in these current scenarios is significantly higher than any of the PACR scenarios. Coupled with the emissions abatement and renewable energy policy assumptions, higher demand drives a faster build of wind and solar in the Base Case, giving greater opportunity for HumeLink benefits to accrue through avoided investment in generation, storage and REZ transmission.

7. Comparison to AEMO ISP take-one-out-at-a-time outcomes

As part of the Draft 2024 ISP, AEMO published an assessment of the relative market benefits of HumeLink in the Step Change scenario in Appendix 6 *Cost benefit analysis*.[27] This is known as their take-one-out-at-a-time (TOOT) analysis and the approach is described in AEMO's *ISP Methodology* report.[28]

By way of comparison of the NPV of gross market benefits of HumeLink Option 3C in the Step Change scenario:

- The Draft 2024 ISP presents $4,180m NPV in forecast gross market benefits over the outlook period 2024-25 to 2051-52 for HumeLink assumed to be commissioned on 1 July 2029.
- This Report presents $7,254 NPV in forecast gross market benefits over the outlook period 2024-25 to 2048-49 for HumeLink assumed to be commissioned 1 July 2026.

Both values are discounted to 1 July 2023 using a 7% discount rate (in real 30 June 2023 dollars).

The discount rate assumption applied to the three-year difference in commissioning date and outlook period would contribute to this difference in gross market benefits. However, even after accounting for this and other implications of the differences in commissioning date and outlook period, it is likely that the forecast gross market benefits of HumeLink computed using the method and input assumptions in this Report is higher than the Draft 2024 ISP value computed using the TOOT approach.

The higher forecast gross market benefits in this Report could be due to a higher system cost in the Base Case in this Report than the without HumeLink case in the Draft 2024 ISP TOOT analysis, or due to lower system cost in the HumeLink Option 3C case in this Report, or a combination of the two. This may be attributable to the following differences in network modelling approach:

- Relative to the Draft 2024 ISP, the model presented in this Report contains additional network detail in the Southern New South Wales region in order to be able to differentiate between the HumeLink options. The additional detail captures key transmission limits and losses within the Southern New South Wales region. Maintaining the same network model as applied in the HumeLink RIT-T also facilitates comparison to that assessment.

  In contrast, the Draft 2024 ISP network model contains additional detail in separating out the Sydney-Newcastle-Wollongong area as a separate node with limits and losses in the connection to the greater Central New South Wales area. There is also additional network detail in Queensland and South Australia.
- The TOOT analysis uses the Step Change scenario optimal development path for other transmission (committed, anticipated, actionable and future ISP projects). In contrast, the modelling in this Report adopts the committed, anticipated and actionable projects and QNI Connect both with and without HumeLink, and uses the timing advised by proponents for projects where this date is later than the date assumed in the Draft 2024 ISP for the Step Change scenario optimal development path. The consequence of this difference in methodology is this Report assumes later commissioning dates for Central West Orana REZ Transmission Link (Aug 2028 instead of Sep 2027), New England REZ Transmission Link 1 (Sep 2028 instead of Jul 2028), Project Marinus Stage 1 (July 2030 instead of July 2029) and VNI West (Dec 2029 instead of Jul 2029). There are also other future ISP projects that are

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[27] AEMO, 15 December 2023. *Appendix 6 Cost benefit analysis: Appendix to the Draft 2024 Integrated System Plan for the National Electricity Market.* Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 23 February 2024.

[28] AEMO, June 2023, *ISP Methodology*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology. Accessed 23 February 2024.

fixed in the Draft 2024 ISP TOOT analysis that are optional REZ transmission upgrades in this Report (and therefore able to vary with and without HumeLink).

- There are also fundamental differences in how REZ transmission is treated for the REZs directly impacted by HumeLink, i.e. South-West NSW and Wagga Wagga REZs. The TOOT analysis adjusts the REZ expansion limits associated with HumeLink in the without HumeLink case. In the without HumeLink case, it locks in any REZ transmission in these two REZs that is built at least-cost in the with HumeLink case post-HumeLink. In contrast, the modelling in this Report does not allow additional build of transmission to connect to those two REZs in the Base Case or HumeLink case.

There are also some structural differences between the model used in this Report and the Draft 2024 ISP model which may influence outcomes of each model. For example, the model used in this Report computes a solution for hourly build and dispatch of generation, storage and transmission in a single solution, whereas the ISP has a multi-stage approach as described in AEMO's *ISP Methodology* report.[28]

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 2024-25 to 2048-49. The modelling methodology follows the CBA guidelines for actionable ISP projects published by the Australian Energy Regulator[29]. The forecast gross market benefits of HumeLink are calculated as the difference in the system cost that is forecast with and without HumeLink.

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[30] and storage losses which form part of the demand to be supplied and are calculated dynamically within the model,
- retirement / rehabilitation costs to cover decommissioning, demotion and site rehabilitation.

To determine the least-cost solution, the model makes decisions for each hourly[31] 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,
- transmission interconnector flow limits (between regions),
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES, VPP and large-scale battery),

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[29] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 1 February 2024.

[30] For the transmission elements modelled, described in Appendix B.

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

- 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,
- emission and carbon budget constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in NSW through modelling of zones with intra-regional limits and loss equations. The model also includes detailed representation of the Canberra zone by applying a DC low flow model. Within these NSW zones and within other regions, the only other element of the transmission network considered and REZ transmission constraints.[32] 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. FOM costs are another component of the running cost of generators contributing to expected earlier economic retirements[33]. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever the cost of supply is at or above their variable costs and operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PHES, large-scale battery 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, storage hydro preserves energy and PHES 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 the Client, the TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

[32] including an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.

[33] Note that earlier coal retirements are an outcome of the least cost optimisation rather than revenue assessment.

[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 February 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 hourly 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 time-sequential modelling, the categories of costs as listed in Appendix A1 are computed as defined in the RIT-T for actionable ISP projects.

For each scenario and sensitivity with HumeLink, a matched without HumeLink counterfactual (referred to as the Base Case) 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 HumeLink.

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 to 1 July 2023 at a 7% real, pre-tax discount rate, consistent with the 2023 IASR[38].

The forecast gross market benefits of each scenario must be compared to the cost of the HumeLink options to determine the forecast net economic benefit for each 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 the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.[1]

[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.
[38] AEMO, December 2023, *2023 IASR Assumptions Workbook v5.3*. Available at https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 1 February 2024.

Appendix B. Transmission

B1. Regional definitions

Transgrid requested to split NSW into sub-regions or zones in the modelling presented in this Report, as listed in Table 5. In addition, southern NSW 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 Draft ISP but in Transgrid's views, enables better representation of intra-regional network limitations and transmission losses in the relevant parts of the network and allows the three HumeLink options to be differentiated. It is consistent with network model used in the PACR.[39]

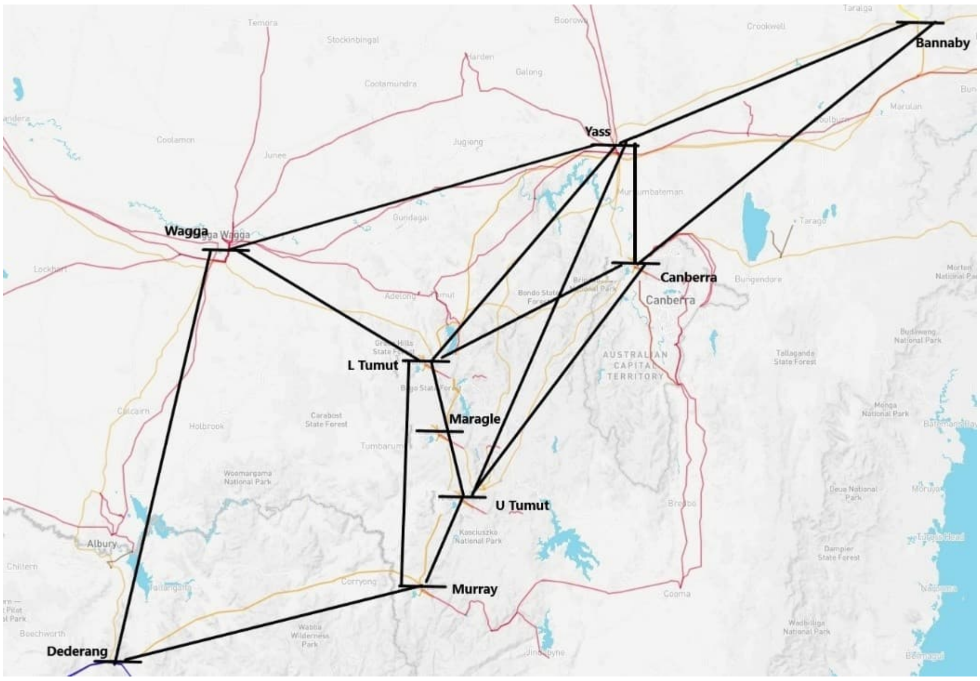
Table 5: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
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
	Snowy (Maragle)	Snowy (Maragle) 330 kV
	Upper Tumut	Upper Tumut 330 kV
Victoria	Murray	Murray 330 kV
	Dederang	Dederang 330 kV
	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

To achieve a more detailed forecast of southern NSW network flows, the Canberra subregion is further subdivided into nine nodes including Lower Tumut, Upper Tumut, Maragle, Yass, Canberra, Wagga Wagga, Dederang, Murray, and Bannaby as shown below in Figure 26. The lines are derived by equivalencing the network connecting the given nodes in the subregion. Demand components are split across the nodes based on their half-hourly proportion of the overall NSW load (averaged to hourly). Furthermore, generators within this subregion are mapped into the nearest node.

[39] Transgrid, 29 July 2021, *Reinforcing the NSW Southern Share Network PACR: Market Modelling Report*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf. Accessed 22 February 2024.

Figure 26: Canberra equivalent network[40,41]



The TSIRP models the Canberra zone's flows and losses using 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.

The borders of relevant zones or regions are defined by the cut-sets listed in Table 6, 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 6. 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 for each option (see Table 3)
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 for each option (see Table 3)

[40] This map is a graphical representation of the modelled network, not a map of existing of proposed transmission routes.
[41] Underlying map from AEMO, *AEMO Map*, Available at: https://www.aemo.com.au/aemo/apps/visualisations/map.html. Accessed 21 February 2024.

Border	Lines
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
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 EnergyConnect) 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 EnergyConnect) New 500 kV double circuit from Kerang – Dinawan (after assumed commissioning of VNI West)

Table 7 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid. These limits are the same as those applied in the modelling for the HumeLink PACR.[39]

Table 7: Key cut-set limits

Options	Snowy cut-set	Snowy cut-set + HumeLink lines	Canberra/Yass – Bannaby cut-set	Canberra/Yass-NCEN cut-set	Bannaby-NCEN
Do Nothing	2,870	2,870	2,700	2,700	3,100 Post WSB SIPS project 3,350[42]
Option 1C-new	2,980	5,920	5,330	4,500	4,500 Post WSB SIPS project 4,750
Option 2C	3,080	5,230	5,230	4,500	4,500 Post WSB SIPS project 4,750
Option 3C	3,080	5,372	4,900	4,500	4,500 Post WSB SIPS project 4,750

B2. Interconnector and intra-connector loss models

Dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g., NNS-NCEN, SA-Buronga (EnergyConnect), Bannaby-NCEN,

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

- all the Victorian and southern NSW equivalenced lines between the modelled nodes, through their equivalent resistance, and
- when future upgrades involving conductor changes are modelled e.g., VNI West, QNI and Marinus Link.

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

The Canberra zone transmission network is explicitly modelled through a DC load flow technique incorporating losses in the TSIRP. Additional losses within New South Wales zones and within the remaining NEM regions are captured through an estimate of loss factors for existing and new entrant generators.

B3. Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 8. 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. The model will dispatch across the two links to minimise costs.

Table 8: Notional interconnector capabilities used in the modelling (sourced from AEMO Draft 2024 ISP[14])

Interconnector (From node – To node)	Import[43] notional limit	Export[44] notional limit
QNI[45]	1,165 MW summer 1,170 MW winter	745 MW summer/winter
QNI Connect Option2[46]	2,865 MW summer 2,870 MW winter	2,005 MW summer/winter
QNI Connect Option 5	5,115 MW summer 5,120 MW winter	5,005 MW summer/winter
Terranora (NNS-SQ)	150 MW summer 200 MW winter	50 MW summer/winter
EnergyConnect (Buronga-SA)	800 MW	800 MW
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	462 MW	462 MW

43 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.

44 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.

45 Flow on QNI may be limited due to additional constraints.

46 AEMO, 15 December 2023. *Appendix 5: Network Investments (Appendix to Draft 2024 ISP for the National Electricity market)*. Available at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/appendices/a5-network-investments.pdf?la=en . Accessed 7 February 2024.

Interconnector (From node – To node)	Import[43] notional limit	Export[44] notional limit
Marinus Link (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage	750 MW for the first stage and 1,500 MW after the second stage
VIC-CAN[47]	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[47]	Initial limit: 0 MW After VNI West: 1,207 MW	Initial limit: 0 MW After VNI West: 1,712 MW

NSW has been split into zones with the following limits imposed between the zones defined in Table 9.

Table 9: 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 1/7/2025 4,270 MW after New England Transmission Link 1 3,970 MW after Waratah Super Battery SIPS contract ends 1/7/2030 6,970 MW after New England Transmission Link 2	910 MW summer/winter 3,910 MW after New England Transmission Link 1 6,910 MW after New England Transmission Link 2
WAG-SWNSW (provided by Transgrid)	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,900 MW (after HumeLink with PEC Enhanced) 3,000 MW (after VNI West) for all HumeLink options 1,500 MW after VNI West without HumeLink	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 MW (after HumeLink, with PEC Enhanced) 2,700 MW (after VNI West) for all HumeLink options 1,700 MW after VNI West without HumeLink

B4. REZ free transmission limit capabilities

The REZ transmission limit capabilities before and after transmission upgrades are shown in Table 10. All REZs also have the option to further expand transmission limits beyond these values at an assumed cost, consistent with the Draft 2024 ISP.[14]

Table 10: REZ free transmission limit capabilities used in the modelling (sourced from AEMO Draft 2024 ISP[14])

REZ name	REZ ID	REZ free transmission limit
North Qld Clean Energy Hub	Q2	770 MW 2200 MW (after CopperString 2032)
North West NSW	N1	171 MW

[47] 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.

REZ name	REZ ID	REZ free transmission limit
New England	N2	577 MW 2,577 MW (with New England Transmission Link 1) 3,577 MW (with New England REZ Upgrade) 6,577 MW (with New England Transmission Link 2)
Central-West Orana	N3	900 MW 5,400 MW (with Central-West Orana REZ Transmission Link)
Broken Hill	N4	250 MW
South-West NSW	N5	215 MW but group constraint for existing generators also noted 1,015 MW (with EnergyConnect) 1,015 MW (with VNI West without HumeLink and HumeLink Option 1C-new) 1,815 MW (with HumeLink Option 2C or Option 3C) 2,715 MW (with HumeLink Option 2C or 3C and VNI West)
Wagga Wagga	N6	1,100 MW 1,100 MW (without HumeLink and Option 1C-new) 2,600 MW (with HumeLink Option 2C or Option 3C)
Tumut[48]	N7	700 MW (with HumeLink Option 2C or Option 3C)
Murray River	V2	440 MW summer/640 MW winter 2,020 MW (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 930 MW (with EnergyConnect)
North-West Tasmania	T2	277 MW summer/112 MW winter No upgrades after Marinus Link
Central Highlands	T3	527 MW No upgrades after Marinus Link

[48] Wind and resource limit at Tumut is zero

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 ranging from 2010-11 to 2018-19. Demand timeseries were provided to Transgrid by AEMO based on their ESOO 2023[49] which was adopted by AEMO for the Draft 2024 ISP.[2] 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 27.

Figure 27: 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

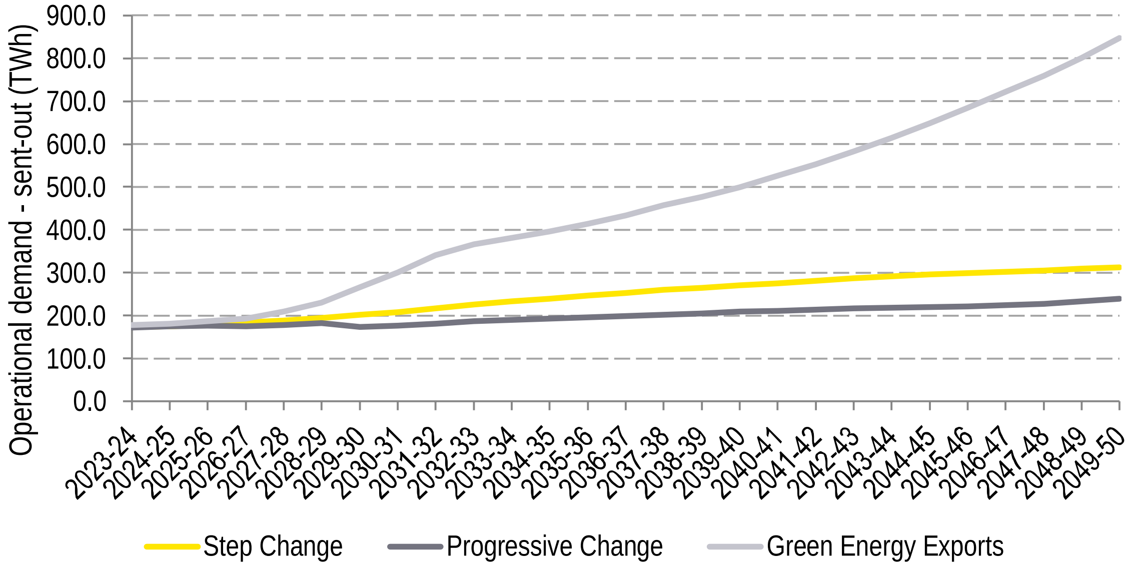
This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed 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 D6) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

[49] 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 February 2024.

The client selected demand forecasts from the ESOO 2023[50] consistent with the relevant scenarios in the 2023 IASR[51], which are used as inputs to the modelling. Figure 28 shows the assumed NEM operational demand for the modelled scenarios, inclusive of hydrogen demand.

Figure 28: Assumed annual operational demand in the modelled scenarios for the NEM



50 AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 1 February 2024.

51 AEMO, December 2023, *IASR Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 1 February 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 2023 IASR Assumptions Workbook[51] for existing, committed, and anticipated projects.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[52] and the methodology for each category of wind and solar project is summarised in Table 11. All large-scale wind and solar availability profiles are developed by EY.

Table 11: 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[53,54] 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[55,56].	
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2023 ISP Inputs and Assumptions workbook[57]. One high quality option and one medium quality option per REZ.	

[52] 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 February 2024.

[53] 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 February 2024.

[54] On the whole, capacity factor estimates for existing projects have not materially changed between the HumeLink RIT-T and this Report.

[55] 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 February 2024.

[56] 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 2023 IASR for the relatively small number of committed generators.

[57] AEMO, December 2023, *IASR Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 1 February 2024.

Technology	Category	Capacity factor methodology	Reference year treatment
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[58,56].	
	Generic REZ new entrant	Reference year specific targets based on AEMO's Draft 2024 ISP Inputs and Assumptions workbook[60].	

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 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 27.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[59] 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 Draft 2024 ISP inputs and assumptions[60] 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 Draft 2024 ISP inputs and assumptions workbook[60].

- 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.

[58] 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 February 2024.

[59] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. 1 February 2024.

[60] AEMO, December 2023, *Draft 2024 ISP Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 1 February 2024.

- 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 Draft 2024 ISP input and assumptions workbook also includes intra-regional flow between nodes within the same region in Queensland and South Australia.[61] Due to using a simplified nodal model for these regions in order to accommodate additional network detail in the Southern New South Wales area, it is not possible to model some intra-regional flows for REZ transmission limits in Queensland and South Australia while maintaining reasonable simulation times. As a result, the Client has agreed to revert to the final 2022 ISP assumptions for REZs which in the Draft 2024 ISP contained in intra-regional flow constraints.[62] This also maintains greater continuity with the RIT-T network model.

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 Draft 2024 ISP input and assumptions workbook.[61]

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and the with HumeLink 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 Draft 2024 ISP Inputs and Assumptions workbook.[61]

D3. Generator technical parameters

Technical generator parameters applied are as detailed in the Draft 2024 ISP inputs and assumptions Workbook[61] 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 Draft 2024 ISP Inputs and Assumptions Workbook[61], 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.

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[61] AEMO, 15 December 2023, *2024 Draft ISP Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 1 February 2024.

[62] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 1 February 2024.

In line with the Draft 2024 ISP Inputs and Assumptions Workbook[61], a minimum load of 46% of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

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

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 in Section D1.

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 Draft 2024 ISP Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[61].

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 September 2023 (in line with all other generators in the NEM)[63]. Figure 29 shows the modelled Snowy Hydro scheme[64]. 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.

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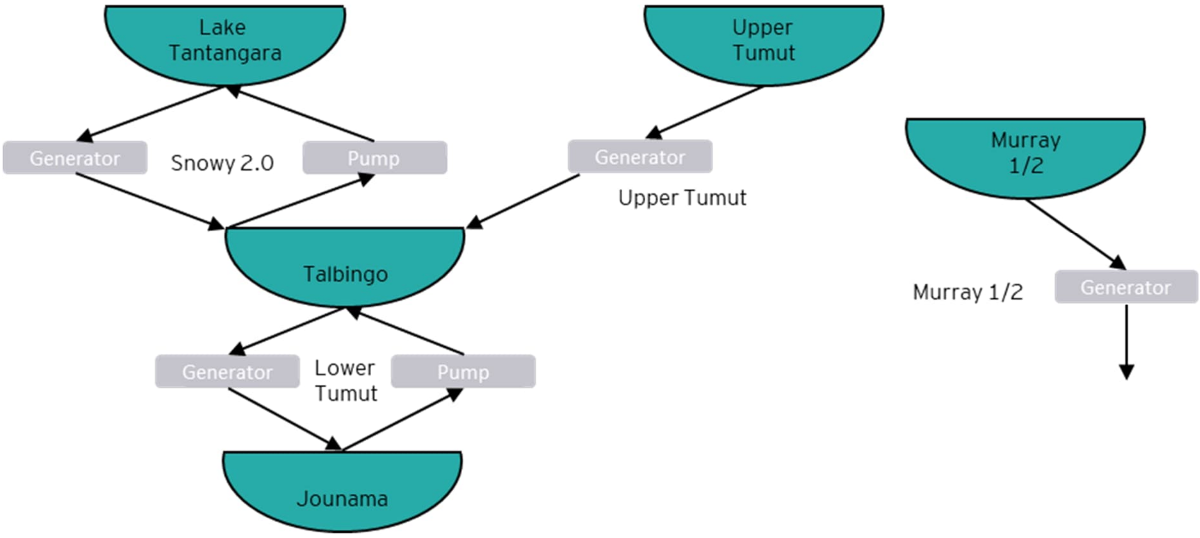
[63] AEMO, September 2023, *NEM Generation Information October 2023.* Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 1 February 2024.

[64] 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 February 2024.

Figure 29: Snowy Hydro scheme topology[65]



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%[66]. The methodology allocates matching amounts of generation 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.

Since the model can look ahead in time, equivalent to factoring in weather forecasts up to seven days, 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 will increase to conserve water. Conversely, if there is low marginal cost generation available to pump, the marginal cost of generation from Snowy 2.0 will also reduce.

[65] 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 February 2024.

[66] AEMO, December 2023, *2023 IASR Assumptions Workbook v5.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation . Accessed 1 February 2024.

Appendix E. 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
GW	Gigawatt
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
IASR	Inputs, Assumptions and Scenarios Report
$m	Million dollars
MCC	Material Change in Circumstance
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
PACR	Project Assessment Conclusions Report
PHES	Pumped Hydro Energy Storage
PSL	Prudent Storage Level
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target

Abbreviation	Meaning
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
SWNSW	South-West New South Wales
TAS	Tasmania
TOOT	Take-one-out-at-a-time
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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