AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Appendix A6. Cost Benefit Analysis

June 2026

Appendix to the 2026 Integrated System Plan for the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This is Appendix A6 to the 2026 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 20 April 2026 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1	25/06/2026	First release

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AEMO's *Integrated System Plan* (ISP) is a roadmap for the National Electricity Market's (NEM's) transition and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet both consumer needs and government policies, at least cost, to 2050.

The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies. This appendix provides a detailed walkthrough of the process used in 2026 ISP to arrive at the actionable transmission investments in the ODP, including:

- an assessment of the various transmission projects and their individual value,
- a consideration of the risks to consumers of over- and under-investment across scenarios, and
- a test of resilience of the ODP to uncertainties captured through sensitivity analysis.

The analysis is underpinned by the consulted-on modelling approaches in the *ISP Methodology*[1], updated in June 2025 to complete a four-yearly review requirement and to incorporate the Energy Ministers' response[2] to the review of the ISP.

This appendix complements the generation and storage developments provided in detail in Appendix A2 Generation and Storage Development Opportunities.

The optimal development path

The ODP covers a range of generation, storage, transmission, and distribution development opportunities. For transmission investments, the identification of projects as actionable will lead to further action by each network proponent – to refine, consult, evaluate, and potentially seek revenue and deliver the project.

This appendix shows that the set of actionable projects in **Table 1** facilitates the transition to a low-emissions electricity system in line with government policy, while minimising costs to consumers. The ODP in this 2026 ISP features:

- **eight committed and anticipated transmission** projects[3] which are underway and will add 3,500 km to the network over the next eight years,
- **twelve actionable projects** to add 1,660 km over the next 12 years – five of these were already actionable, five were future projects in the 2024 ISP and now fall within the actionable window, and two are new projects in this ISP, and
- **a number of future ISP projects** which are forecast to be actionable under at least one future scenario, including two projects that were previously actionable.

The reported cost[4] of these newly actionable projects amounts to $4.4 billion, while the cost for the projects that have lost ongoing actionability amounts to $8.2 billion.

[1] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology.

[2] At ecmc-response-to-isp-review.pdf.

[3] Note that transmission projects that are committed or anticipated are not included in the ODP costs discussed below.

[4] 'Reported cost' refers to the estimate prepared by the transmission network service provider (TNSP), or by AEMO and reviewed by the TNSP.

Table 1 Network projects in the optimal development path in the 2026 ISP

Committed and anticipated transmission projects		In service timing[A]	Full capacity timing[B]
Project EnergyConnect Stage 2		October 2026	November 2027
HumeLink		December 2027	December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central-West Orana REZ Network Infrastructure Project		December 2028	December 2028
Western Renewables Link		November 2029	November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		2032	2032[C]
New England REZ Network Infrastructure Project[D]		January 2034	January 2034
Already actionable projects (confirmed in this ISP)	**Framework**	**In service timing[A]**	**Full capacity timing[B]**
Gladstone Project	QLD[E]	March 2029	Mid-2030[C]
Sydney Ring North (Hunter Transmission Project)	NSW[E]	November 2029	November 2029
Sydney Ring South	ISP	Power flow control: July 2030 500 kilovolts (kV) assets: July 2033	Power flow control: July 2030 500 kV assets: July 2033
Victoria – New South Wales Interconnector West (VNI West)	NSW[E] ISP	South West REZ: August 2029 NSW-VIC: November 2030	South West REZ: August 2029[C] NSW-VIC November 2031
Project Marinus Stage 2	ISP	June 2034	December 2034
Newly actionable projects (identified in this ISP)	**Framework**	**Earliest feasible full capacity timing[B]**	
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[E]	June 2029	
Tasmania REZ Expansion (future project in 2024 ISP)	ISP	July 2030	
Switching Station Near Wondalga	ISP	April 2031[C]	
Central to North Queensland Reinforcement (Stage 1) (smaller option of Queensland SuperGrid North project in 2024 ISP)	ISP	July 2031[C]	
Gippsland Offshore Wind Transmission Project (future project in 2024 ISP)	VIC[E]	Stage 1: July 2031; Stage 2 – Phase 1: July 2033; Stage 2 – Phase 2: July 2038	
Brisbane Area 275 kV Reinforcement	ISP	June 2032	
Central-West Orana REZ Expansion (future project in 2024 ISP)	NSW[E]	March 2033	
Future ISP projects[F]			
Interconnector projects	**Queensland – New South Wales Interconnector (QNI Connect)**		
Queensland	**Central to North Queensland Reinforcement (Stage 2), South West to South East Queensland Reinforcement**		
South Australia	**Northern Transmission Project[G]**		
Victoria	**Eastern Victoria Reinforcement, South West Victoria Expansion**		
Tasmania	**Second Tasmania REZ Expansion**		
Distribution projects			
New South Wales	**Hunter-Central Coast REZ Expansion, Dubbo Distribution Project**		

A. The in service date, advised by the project proponent, gives an indication of when construction and commissioning will be complete and equipment in-service.
B. The capacity release and timing, advised by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.
D. This project is newly categorised as anticipated. It is progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).
E. These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), *Electricity Infrastructure Investment Act 2020* (NSW), or the *National Electricity (Victoria) Act 2005* (Vic), rather than the ISP framework.
F. This list shows future ISP projects which are identified as part of the ODP in *Step Change* or are subject to an ongoing regulatory investment test for transmission (RIT-T). Appendix A5 Network Investments provides information about additional future ISP projects identified in only one scenario.
G. AEMO considers ElectraNet should continue the Northern Transmission Project RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options.

Net market benefits of the ODP

This ODP is projected to reduce costs that the system would otherwise need to bear by the order of $28 billion, on a **weighted basis across the scenarios**, which includes emissions reduction benefits valued at $1.5 billion. As further discussed in Section A6.6.1, weighted net market benefits have increased since the Draft 2026 ISP.

The present value (PV) of the annualised capital costs from now to 2049-50 of all additional investments in utility-scale generation, storage, firming, and transmission and distribution networks[5] in the ODP beyond committed and anticipated developments would be $106 billion in *Step Change*. The transmission element of this annualised capital cost to 2050 would be $6.3 billion in PV terms, or 6% of the total. As the assets have a technical life beyond 2050, the total present value of the overnight capital costs of these investments is $133 billion.

All other assessed combinations of generation, storage, firming and network technologies, seeking to meet consumer needs and government policies, would cost more than the ODP.

The ODP delivers the highest **weighted net market benefits** (WNMB), totalling $28 billion across the three scenarios, compared to all alternative candidate development paths (CDPs) assessed in this ISP (see **Table 2**). As **Table 2** shows, the WNMB across the CDPs are relatively similar, reflecting the high degree of commonality in the underlying transmission investment portfolios. By the stage at which thousands of development paths are narrowed to a limited set of CDPs, most pathways include a similar set of projects, with the primary point of differentiation being timing – particularly whether projects are progressed as actionable or deferred. As a result, differences in net market benefits across CDPs are driven largely by sequencing and timing effects rather than fundamentally different development strategies.

The benefits for each CDP are measured relative to a ‘no transmission’ counterfactual development path with no new transmission beyond committed and anticipated projects, requiring greater investment in utility-scale generation and storage in each region, including gas-powered generation (with and without carbon capture and storage [CCS]) and mid-scale solar. This ‘no transmission’ counterfactual development path is more costly as it limits the sharing of electricity across the NEM and constrains access to high-quality renewable resources.

Most of the benefits therefore arise from avoided or deferred investment in generator, storage and electrolyser capacity, compared to the ‘no transmission’ counterfactual development path, as well as avoided fuel costs (see **Figure 1** for a breakdown of the WNMB for the ODP).

In a future perfectly aligned with *Step Change*, the following projects would be delivered at an actionable timing to minimise total system costs: Gladstone Project, Sydney Ring North (Hunter Transmission Project), Sydney Ring South, both power flow control and 500 kilovolts (kV) assets Stages 1 and 2, VNI West, Western Victoria Reinforcement, Tasmania Renewable Energy Zone (REZ) Expansion, Switching Station Near Wondalga, Gippsland Offshore Wind Transmission Project, including Stage 1, Stage 2 – Phase 1 and Stage 2 – Phase 2, Brisbane Area 275 kV Reinforcement, and Central-West Orana REZ Expansion. These projects form **CDP 2** – the least-cost development path (DP) in *Step Change*.

Considering the outcomes of the other scenarios and the sensitivity analysis, the ISP selects **CDP 4** as the ODP. Most analyses presented in this appendix are therefore relative to CDP 4**.** CDP 4 is based on CDP 2 but includes an actionable Project Marinus Stage 2, actionable Central to North Queensland Reinforcement (Stage 1), and delivery of Hunter-Central

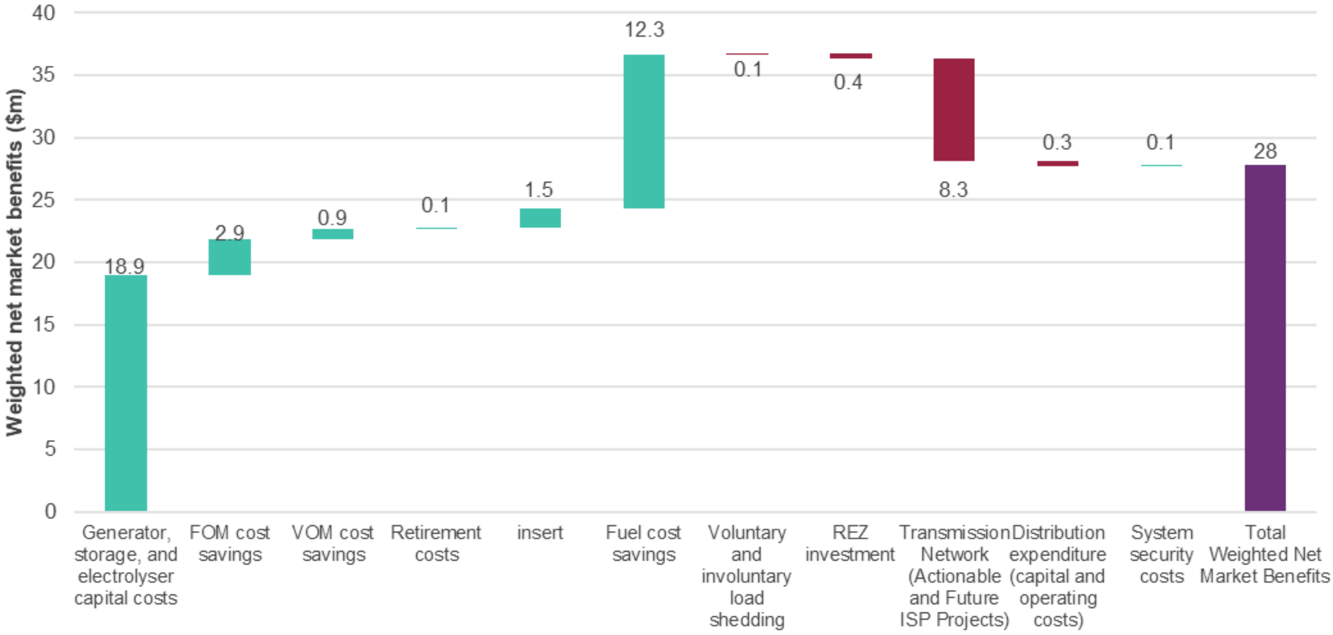
[5] As discussed in Section A9.4.1, distribution network investments identified in the 2026 ISP specifically relate to economically efficient distribution network investments to specifically enable greater export of CER from consumers’ homes and business into the distribution network. They also refer to certain distribution network development opportunities to facilitate connection of utility-scale generation and storage to the distribution network, as discussed in Section A5.5.

Coast REZ Expansion; reflecting their benefits at their earliest-in-service date in either one or more of the other two scenarios.

CDP 3, ranked last in **Table 2**, is the least-cost DP in *Accelerated Transition.* It includes delivery of the Central Highlands REZ option at an actionable timing, and Dubbo Distribution Project (Option 1 and 2a) at their earliest in-service dates (EISDs).

Not only does the ODP deliver the highest WNMB, as shown in **Table 2**, the ODP appropriately balances the risk to consumers of over- and under-investment – being ranked fifth- on worst weighted regrets and at marginal additional regret compared to higher-ranked CDPs. The greatest regret associated with the ODP reflects the potential risk of over-investment in *Slower Growth*, which is underpinned by lower overall growth in energy consumption and explicit closures of large energy-intensive industrial loads.

Figure 1 Weighted net market benefits of the ODP by category



Note: Bars shaded teal represent additional weighted benefits compared with the 'no transmission' counterfactual development path, while bars shaded red represent additional weighted costs.

Table 2 Top 10 candidate development paths (CDPs) across the three scenarios (in $billion), in order of descending weighted net market benefits

CDP	Description	*Slower Growth*	*Step Change*	*Accelerated Transition*	WNMB	Rank based on WNMB	Worst weighted regrets (WWR)	Rank based on WWR
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	10.29	29.55	42.55	27.86	1	0.14	5
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	10.30	29.58	42.47	27.85	2	0.14	3
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	10.29	29.54	42.53	27.85	3	0.14	6
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	10.30	29.52	42.50	27.84	4	0.14	1
CDP 14	CDP 4 without actionable Central-West Orana REZ Expansion	10.43	29.43	42.52	27.83	5	0.16	9
CDP 27	CDP 4 with actionable Central Highlands REZ option	10.25	29.50	42.56	27.83	6	0.15	7
CDP 18	CDP 4 without actionable Eastern Victoria Reinforcement Option 1	10.20	29.54	42.55	27.83	7	0.16	10
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	10.30	29.50	42.51	27.83	8	0.14	2
CDP 25	CDP 4 without actionable North West Tasmania REZ option	10.29	29.50	42.50	27.82	9	0.14	4
CDP 3	Least-cost DP for *Accelerated Transition*	9.97	29.49	42.71	27.79	10	0.23	14

Additional scope is now included in the system costs assessed in the ISP

In response to the recommendations of the review of the ISP agreed by Energy and Climate Change Ministerial Council (ECMC) in 2024[6], the total system cost assessed in the 2026 ISP now includes the costs of distribution network augmentations, system security, and mid-scale generation and storage (other distributed resources)[7].

Figure 2 presents this inclusion, and how the total system capital costs in the 2026 ISP are compared with the total system capital cost figure in the 2024 ISP. The figure shows that, excluding these new scopes, and once the impact of inflation, time value of money, and the value of anticipated and committed projects is accounted for, the capital costs in the ODP are nearly $6 billion, or 7% higher than in the 2024 ISP. As seen in Draft GenCost 2025-26[8], the cost of gas, wind and offshore wind have all increased since the 2024 ISP in real terms, while utility-scale solar photovoltaics (PV) and batteries have reduced. As outlined in Section A2.2.2 of Appendix A2, between July 2025 and January 2026, a significant number of generation, storage and transmission projects are now classified as either committed, anticipated, or policy-supported projects with over 15.8 gigawatts (GW)/60.3 gigawatt hours (GWh) of utility-scale storage, 4.8 GW of utility-scale solar, and 1 GW of wind capacity, in addition to 0.06 GW of flexible gas and 3,500 km of network augmentations. As outlined in the *ISP*

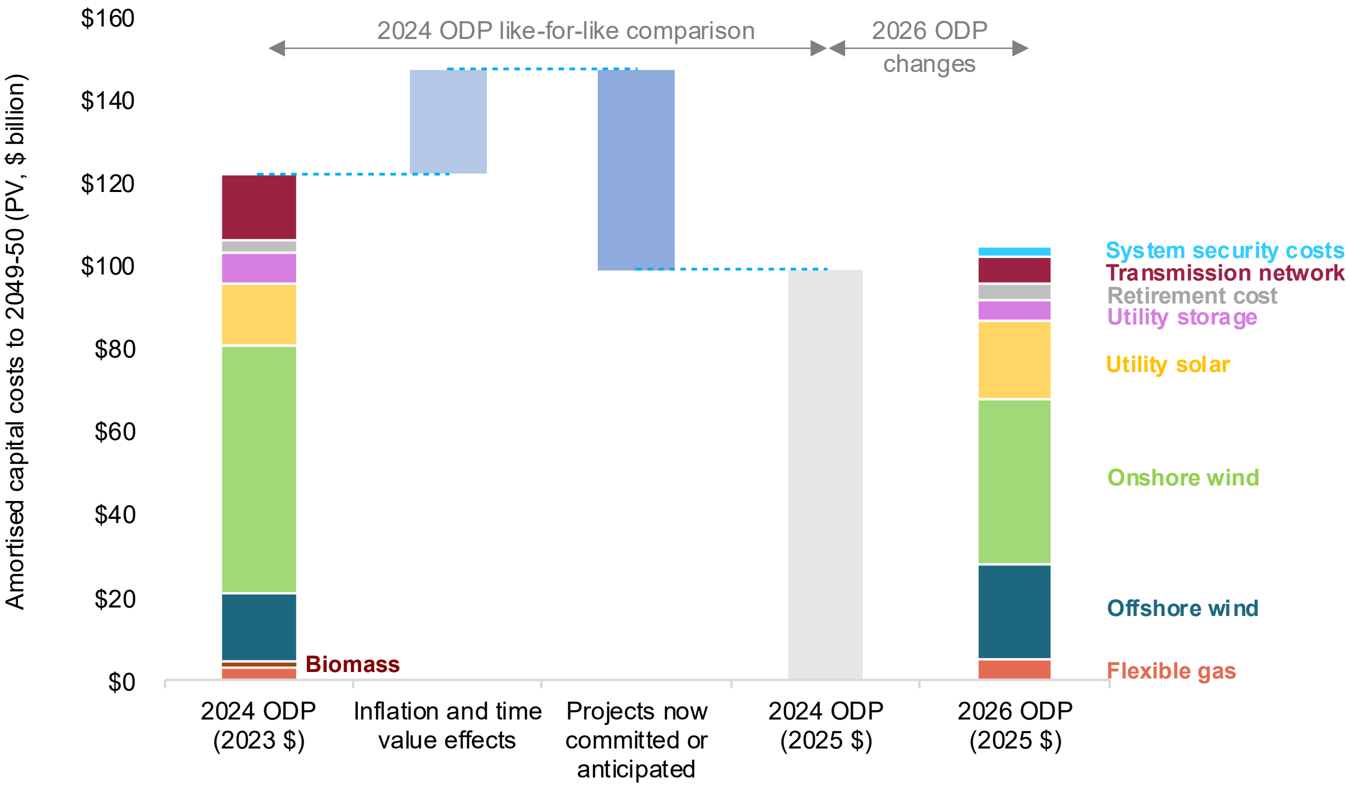
[6] At https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf.

[7] Refers to utility-scale solar and storage installations that are connected at the high-voltage section of the distribution network and are assumed to be limited to 30 megawatts (MW).

[8] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

Methodology, these investments are expected to proceed in all futures, and therefore each investment is not costed as part of the cost-benefit analysis, as their costs have no impact on the investment decisions of future decisions.

Figure 2 Component of capital costs between the 2024 ISP and the 2026 ISP



Sensitivity analysis confirms the selection of the ODP

AEMO's modelling demonstrates that the ODP provides an appropriate resilience and robustness to future uncertainties using a scenario planning approach and assessment of individual uncertainties through sensitivity analysis.

The 2026 ISP presents several sensitivities, including:

- *Constrained Delivery*, which explores the impact on consumer benefits if generation, storage and transmission projects were delivered faster than has been achieved to date, but still not as fast as in the ODP – this sensitivity applies slower build rates and higher capital costs, reflecting potential constraints such as planning approvals and the need for social licence, the supply chain, or construction,
- *Higher Demand* – to explore the robustness of the ODP to higher uptake of data centres and large industrial load across the NEM, and
- other alternative assumptions on demand-side factors such as *No Further VPP Uptake, No Further CER Coordination*, *Lower Energy Efficiency* and *Higher Energy Efficiency*.

As **Table 3** shows, CDP 4 delivers the highest-ranked or second highest-ranked weighted net market benefits across all six sensitivities. CDP 4 represents the highest weighted net market benefits across the CDP collection; given its robust performance across the set of alternative assumptions tested through sensitivity analysis, AEMO identifies CDP 4 as the

ODP. CDP 3, which has one more actionable transmission project than CDP4, has the highest WNMB in two of the six sensitivities.

Table 3 Relativity of weighted net market benefits (in $ billion) for each key CDP across the sensitivity collection

CDP	Description	*Core Assumptions*	*Constrained Delivery*	*Higher Demand*	*No Further VPP Uptake*	*No Further CER Coordination*	*Lower Energy Efficiency*	*Higher Energy Efficiency*
Weighted net market benefits								
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	27.86	30.26	42.10	28.42	28.70	30.47	25.81
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	27.85	30.23	42.07	28.42	28.70	30.46	25.81
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	27.85	30.20	42.08	28.42	28.70	30.46	25.80
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	27.84	30.25	42.07	28.41	28.68	30.45	25.80
CDP 3	Least-cost DP for *Accelerated Transition*	27.79	30.34	42.16	28.35	28.64	30.40	25.74
CDP 2	Least-cost DP for *Step Change*	27.67	29.93	41.64	28.23	28.48	30.22	25.69
CDP 1	Least-cost DP for *Slower Growth*	26.84	28.78	38.91	27.43	27.74	29.29	25.06
Change in weighted net market benefits relative to most beneficial CDP								
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	0.00	-0.08	-0.06	0.00	0.00	0.00	0.00
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	0.00	-0.11	-0.09	0.00	0.00	-0.01	0.00
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	-0.01	-0.14	-0.08	-0.01	-0.01	-0.01	-0.01
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	-0.02	-0.09	-0.09	-0.02	-0.02	-0.02	-0.01
CDP 3	Least-cost DP for *Accelerated Transition*	-0.07	0.00	0.00	-0.07	-0.07	-0.06	-0.08
CDP 2	Least-cost DP for *Step Change*	-0.19	-0.41	-0.52	-0.20	-0.23	-0.25	-0.12
CDP 1	Least-cost DP for *Slower Growth*	-1.01	-1.56	-3.25	-0.99	-0.96	-1.18	-0.75

Note: Cells shaded teal represent the top-ranked CDP amongst those presented in the table for each sensitivity.

Key changes since the Draft 2026 ISP[9]

AEMO has incorporated several changes to key inputs and assumptions since publication of the Draft 2026 ISP in response to stakeholder feedback and recent market developments, which include:

- including 15.8 GW/60.3 GWh GW of utility-scale storage, 4.8 GW of utility-scale solar, and 1 GW of wind capacity by 2029-30, that now meet the criteria to be classified as committed, anticipated[10], and policy-supported projects as part of the January 2026 Generation Information update,
- better representing the known pipeline of incoming generation and storage projects ahead of generic project builds to 2029-30,
- improving the assumptions around the flexibility of coal by applying recent minimum continuous operating levels for coal plants which reflect more flexible operation,
- updating consumer batteries forecasts to capture the Federal Government's Cheaper Home Batteries Program (CHBP)[11], increasing the forecast capacity of consumer energy resources (CER) batteries,
- updating gas fuel prices based on ACIL Allen's forecast[12], aligning to updated information for the 2026 *Gas Statement of Opportunities* (GSOO), and revised capital costs of generation and storage technologies, as forecast in CSIRO's Draft 2025-26 GenCost[13] publication, considering stakeholder feedback,
- updating the representation of Capacity Investment Scheme policies to better reflect recent tender announcements,
- updating the formulation of South Australia's 100% net renewable electricity target to correctly represent the policy,
- improving network representations of some REZs and flow paths[14], in conjunction with addition of new network options and updated status of New England REZ Network Infrastructure Project as anticipated,
- reflecting technology-specific access right capacity limits for new wind and solar technologies as well as operating limits for oversized access right holders, and
- including site generation limits for hybrid stations to ensure co-located generation and storage assets do not exceed the registered site capacity based on updated generation information.

A full description of key changes is provided in Section A6.3.

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[9] AEMO has published all inputs and assumptions within the 2026 ISP Inputs and Assumptions Workbook, including a log of changes.

[10] Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated. Projects with known timing, satisfying all five of the commitment criteria are assigned a commitment status classification of committed. More information can be found in the Generation Information publication at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[11] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

[12] At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf?rev=91c2467e5f3c4aa1b9a2b2c6c75a976a&sc_lang=en.

[13] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

[14] Flow paths are a feature of power system networks, representing the main transmission pathways over which bulk energy is shipped. They are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the network to load centres.

A6.1 Introduction

AEMO's ISP represents a roadmap for the energy transition of the NEM, laying out the optimal development path (ODP) which details the needed generation, storage, and network investments to meet both consumer needs and government energy and emissions targets to 2050.

This appendix of the 2026 ISP sets out the process and rationale for identifying the ODP from a range of **candidate development paths (CDPs)**. CDPs represent a shortlist of possible alternative 'potentially actionable' transmission developments, including each scenario's least-cost **development path (DP)** and several alternative DPs that perform well across the scenarios but may not be the best in any given scenario.

This appendix details the implemented cost-benefit analysis (CBA) and presents the analyses on each of the CDPs across the three ISP scenarios and across a range of alternative sensitivities. In this appendix:

- A6.2 provides a summary of the overall approach to the CBA.
- A6.3 describes the key changes since the Draft 2026 ISP.
- A6.4 illustrates the process of determining the least-cost DP and presents the projects that make up each scenario's least-cost DP.
- A6.5 outlines the development of the set of CDPs based on the least-cost DPs.
- A6.6 provides a detailed assessment of individual transmission and distribution projects by examining their individual impact and the value that they provide by being declared as actionable projects.
- A6.7 identifies the preliminary ODP based on the core set of assumptions.
- A6.8 tests the resilience and robustness of the preliminary ODP and a subset of the CDP collection to changes in assumptions through sensitivity analysis.
- A6.9 finalises the identification of the ODP after considering the entirety of the analysis.

Other notes relevant to this appendix

All values presented in this appendix are on a 30 June 2025 real dollars basis unless stated otherwise. Net present value (NPV) outcomes are discounted back to 30 June 2025 by applying the relevant discount rate. All NPVs consider an outlook period from 2026-27 to 2049-50.

The cost estimates for transmission projects in this appendix represent the cost in the year of delivery, expressed in June 2025 dollars. For this reason, projects will have different costs in development paths where they are delivered in different years. This reflects the application of AEMO's transmission cost forecasting approach, which is explained in the *2025 Electricity Network Options Report*[15]. These costs may appear differently to those presented in Appendix A5 Network Investments, which displays the cost for delivery in a fixed year.

[15] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/final/2025-electricity-network-options-report.pdf.

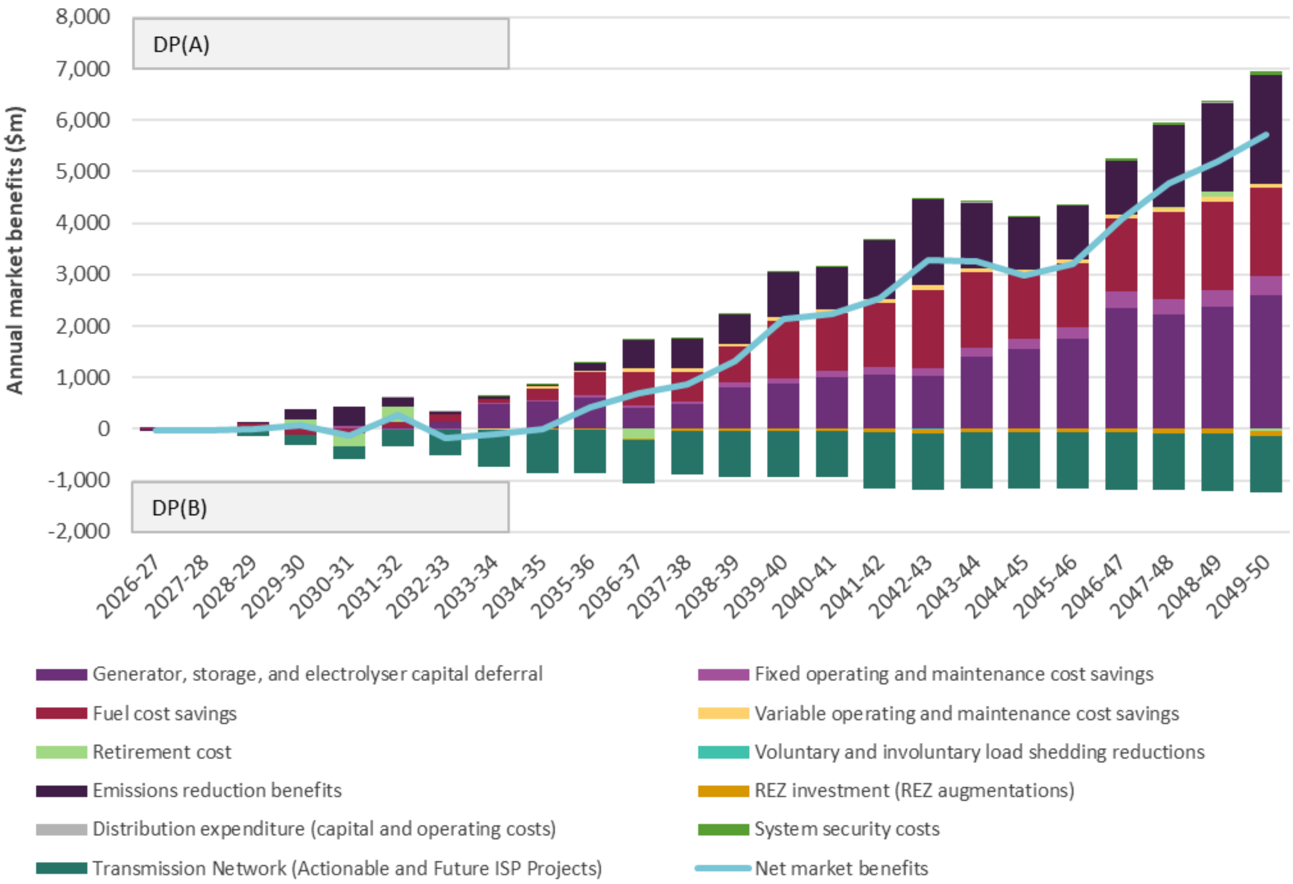
This appendix is supported by the **2026 ISP generation and storage outlook**[16], which also provides a breakdown of the difference in total system costs between CDPs.

Interpreting the graphics in this appendix

This appendix presents a number of charts comparing the projected benefits of two different DPs over the outlook period, with an example shown in **Figure 3** below. The charts present the relative costs or benefits of these two alternatives and do not present the gross benefit of each benefit class for each development path individually. When interpreting this type of chart:

- The stacked columns illustrate the projected values for different classes of market benefits on an annual undiscounted basis.
- Noting the DP(A) and DP(B) labels on the left-hand side of the chart area, positive values indicate greater benefits (cost savings) associated with DP(A) relative to DP(B) and negative values indicate additional costs incurred in DP(A) compared with DP(B). For example, the dark purple bars above the x-axis represent generation capital deferral cost savings in DP(A), while the turquoise bars below the x-axis indicate greater transmission costs in DP(A) compared with DP(B).

Figure 3 Example interpretation of annual market benefits used in this appendix



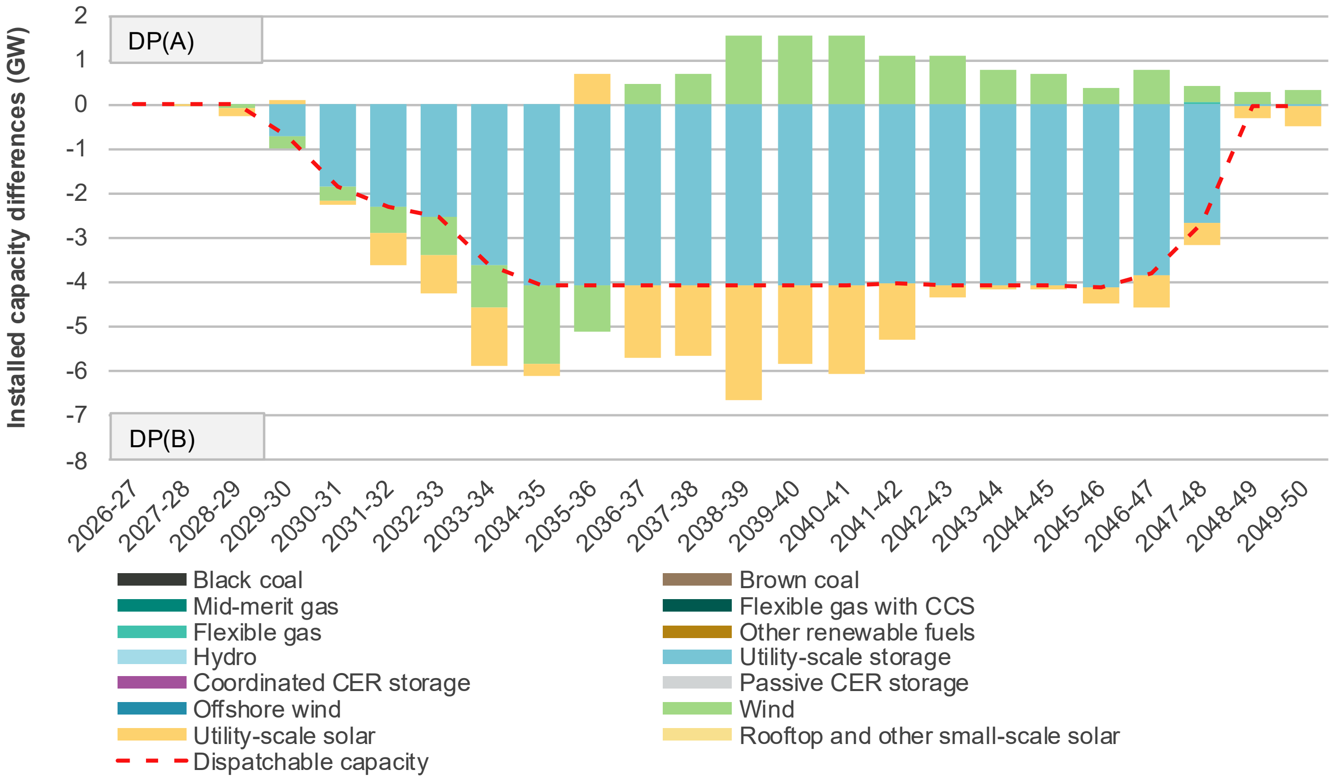
16 At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

This appendix also presents charts comparing the projected capacity and generation differences over the outlook period of two different development paths, as shown in the example figure below. When interpreting charts like the one below in **Figure 4**:

- The stacked columns show the projected values (capacity or energy generated) for different technologies on an annual basis.
- The values reflect the relative difference between the two generation mixes in the two development paths. A positive value indicates a higher total capacity (or generation) in DP(A) relative to DP(B) and a negative value indicates a higher capacity (or generation) in DP(B) relative to DP(A). For example, the yellow bar that is below the x-axis indicates there is higher capacity of utility-scale solar in DP(B) relative to DP(A).
- The line represents the projected difference in total dispatchable capacity between the two DPs. Dispatchable capacity refers to generation and storage capacity that can adhere to dispatch instruction, being controllable and flexible, and can provide greater certainty on its availability in any given dispatch interval.

See the glossary at the end of this appendix for definitions of the different classification of energy supply technologies.

Figure 4 Example interpretation of forecast capacity differences used in this appendix



A6.2 Approach to the cost-benefit analysis

The 2026 ISP applied AEMO's *ISP Methodology*[17] which details the approach used in the modelling and the CBA that underpins the determination of the ODP. The updated *ISP Methodology* was developed in accordance with the Australian Energy Regulator's (AER's) *Forecasting Best Practice Guidelines*[18] and *Cost Benefit Analysis Guidelines* (CBA Guidelines)[19], last consulted on in November 2024. It sets out the principles that govern the following aspects of the CBA:

- the quantification of costs and classes of market benefits that are considered in the ISP,
- the determination of the least-cost DP for each scenario and the development of the CDPs (Step 1 of the CBA),
- the evaluation of net market benefits compared with the 'no transmission' counterfactual DP[20],
- the process for assessing the CDPs across all scenarios (Step 2),
- the process for ranking CDPs according to weighted net market benefits (WNMB) and worst weighted regrets (WWR)[21] (Steps 3 and 4), and
- the determination of the ODP after considering sensitivity analysis (Step 5).

A6.2.1 Key definitions

The glossary at the end of this appendix provides a number of important definitions. Terms defined in the National Electricity Rules (NER), AER guidelines, or the *ISP Methodology* have the meanings given in those documents. Other key terms specifically used in this appendix are summarised below for reference:

- The **earliest in-service date (EISD)** of an ISP project is the earliest date the project can be completed. For most actionable projects, it is also when they are assumed to be delivered.
- An **actionable window** is a period set such that the CBA can identify that a project should be actioned now rather than being actioned in a future ISP.
  - For new actionable projects, the length of the actionable window is two years. In practice, this means that if the project is not required until two years after the EISD, then the project is likely better to be deferred until the next iteration of the ISP, unless potential risks or regrets deem it more appropriate to deliver it earlier.
  - For a project that was first made actionable in the previous ISP, the actionable window is increased by two years to a total of four years (the project has been advancing for two years already, and if it does not maintain its actionability, the EISD would slip by two years because regulatory approvals, early works or preparatory activities may need to be repeated or renewed if it is subsequently actioned in future). Projects are assessed within, or

[17] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

[18] At https://www.aer.gov.au/industry/registers/resources/guidelines/forecasting-best-practice-guidelines.

[19] At https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20guidelines%20-%202024%20-%20Version%203.pdf.

[20] In the CBA, net market benefits reflect the difference in discounted total system costs of a given DP relative to a no transmission counterfactual DP (for net market benefits) or another alternative DP (for relative market benefits).

[21] The *ISP Methodology* refers to the 'least-worst weighted regret'; the worst-weighted regret approach described in this appendix is identical to that described in the methodology. This appendix describes the approach for ranking CDPs as ranking in accordance with the worst weighted regret, to find the CDP that provides the least-worst weighted regret.

outside of, its actionable window to assess whether a project that was previously actionable should continue to be progressed.

- For projects that have been actionable for multiple ISPs, the length of the actionable window is two years (to reflect the time period before the next ISP) plus two years for each ISP (excluding ISP updates) in which those projects are declared as actionable, for the same reasons noted above.

- **Potential actionable and future ISP projects** are projects that are being considered and analysed for actionability during the process of determining the ODP for this ISP.

For the assessment of costs and benefits, the following definitions are relevant:

- **Total system cost** is the sum of all system costs included to estimate the classes of market benefits as listed in Section A6.2.3, including the cost of any transmission augmentations.
- **Net present value (NPV)** is the discounted sum of all considered costs and is used to determine the discounted total system cost of each DP.
- **Relative market benefits** reflect the difference in discounted total system costs of a given DP relative to the discounted total system costs of another DP.
- **Net market benefits** are the relative market benefits of a DP compared to the 'no transmission' counterfactual DP.
- A CDP's **WNMB** reflect the weighted average of a CDP's net market benefits across all scenarios. Net market benefits are weighted based on the relative likelihoods of each of the assessed scenarios which were derived considering the insights of an expert stakeholder panel and AEMO's assessment of scenario likelihood.
- **Weighted regret** for a given scenario is the difference in net market benefits between the CDP that has the highest net market benefits and the CDP of interest under the same scenario, weighted by the relative likelihood of that scenario.
- A CDP's **WWR** reflect the highest amount of weighted 'regrets' across the scenarios. The worst weighted regret is associated with risks of over- or under-investment.

A6.2.2 Scenario weightings in the cost-benefit analysis

Under the CBA Guidelines, AEMO is required to use a scenario-weighted average approach to rank the CDPs against each other.

Table 4 shows the scenario weightings determined by AEMO, considering the insights from stakeholder consultation using a consultative, deliberative process involving a panel of experts (see Appendix A1 Stakeholder Engagement and 2026 ISP scenario weighting[22] for more details). These weightings were applied to both net market benefits and worst weighted regrets associated with each CDP in the CBA to allow comparison of CDPs across the set of scenarios.

Table 4 Scenario weightings applied in the cost-benefit analysis

Scenario	Weighting
Slower Growth	27%
Step Change	46%
Accelerated Transition	27%

[22] At https://www.aemo.com.au/-/media/files/major-publications/isp/2026/2026-isp-scenario-weighting-overview.pdf.

A6.2.3 Classes of market benefits

The NER set out the classes of market benefits that must be considered in the ISP. The *ISP Methodology* provides more detailed information on how these relate to the CBA. The classes of market benefits included in AEMO's CBA include:

- **generator, storage, and electrolyser[23] capital deferral** – differences in the timing and scale of new generation, storage and electrolysers within a CDP compared to the 'no transmission' counterfactual development path,
- **fuel cost savings** – costs associated with changes in fuel consumption arising through different patterns of generation dispatch, including the effect that this dispatch has on electrical losses for energy transported across the power system (a DP that facilitates substituting higher fuel cost plant with lower fuel cost plant is captured as a positive market benefit),
- **fixed operating and maintenance cost savings** – differences in recurring generation, storage and electrolyser costs incurred regardless of variation in generator, storage, and electrolyser output (these costs include major and ongoing equipment maintenance and repairs but do not include depreciation and finance costs),
- **variable operating and maintenance cost savings** – differences in non-fuel, generation, storage, and electrolyser costs relating to variation of generator, storage, and electrolyser output, including labour costs and operation and maintenance costs,
- **retirement costs** – the costs of retiring and decommissioning generation and storage assets that are separate from the cost of building new generation and storage (delaying or avoiding generator retirement costs is captured as a positive market benefit),
- **voluntary and involuntary load shedding reductions** – reductions in voluntary load curtailment via demand side participation (reductions in involuntary load shedding are captured as a positive market benefit using the Value of Customer Reliability [VCR]),
- **emissions reduction benefits** – reductions in Australia's greenhouse gas emissions using the AER's value of emissions reduction (VER)[24] are captured as a positive market benefit,
- **transmission network (Actionable and Future ISP Projects)** – capital and operating cost differences associated with differences in the timing of potential actionable or future ISP transmission network projects,
- **REZ investment (REZ augmentation)** – differences in the timing of REZ network infrastructure that is not considered as a potential actionable or future project (the cost of potential actionable and future projects is captured within the transmission network cost class, and delaying or avoiding the cost of a REZ infrastructure investment not considered as a potential actionable or future ISP project within a DP is captured as a positive market benefit),
- **distribution expenditure (capital and operating costs)** – differences in the timing of both capital expenditure for distribution network augmentations to support CER export and mid-scale generation and storage (other distributed resources), and operating and maintenance costs associated with those augmentations (delaying or avoiding distribution expenditure is captured as a positive net market benefit), and

[23] Generally, electrolyser capacities are developed to service the forecast demand for hydrogen, and they may differ between scenarios. Each development path may develop sufficient electrolyser capacity to efficiently deliver the forecast demand for hydrogen differently.

[24] At https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024.

- **system security costs** – differences in costs to maintain power system security (differences in the timing of network investment may affect the retirement timing of synchronous generation and associated system security remediation costs).

Several classes of market benefits within the CBA Guidelines are not explicitly accounted for above, and AEMO's approach to accounting for these classes of benefit is as follows:

- **Additional option value** – AEMO's scenario analysis already includes considerations of option value through the assessment of flexibility in DPs, the approach to identifying the ODP, and through the other classes of market benefits.
- **Changes in ancillary service costs** – as described in the *ISP Methodology*, ancillary costs are not considered as a class of market benefits because AEMO considers these costs are unlikely to materially affect CBA outcomes or selection of the optimal development path.
- **Competition benefits** – competition benefits refer to the increased economic efficiency that may occur from improved competition in the market as a result of investments. As described in the *ISP Methodology*, AEMO does not include competition benefits in the CBA, as the computational cost of calculating these potential benefits is significant for a single investment, and not tractable for the collection of projects that the ISP examines. This is the same treatment as the 2024 ISP.

When estimating the benefits of reducing the risk of involuntary load shedding, the ISP does not capture network resilience benefits associated with mitigating climate change risks (such as bushfires) or any further reduction or avoidance of involuntary load shedding beyond that explicitly assessed in the ISP, in accordance with the CBA Guidelines. Where relevant, these additional benefits are more appropriately explored in a regulatory investment test for transmission (RIT-T) or jurisdictional cost benefit analysis.

A6.3 Key changes since the Draft 2026 ISP

The 2026 ISP reflects several changes in assumptions since the Draft 2026 ISP to capture updated information (as pre-empted in the 2025 *Inputs, Assumptions and Scenarios Report* [IASR]) and stakeholder feedback. This section describes the key changes in inputs and assumptions that have been made in this final 2026 ISP and the impact these changes have had on the development opportunities.

Key changes to the inputs and assumptions are included in the 2026 ISP Inputs and Assumptions Workbook and summarised as shown in **Table 5**[25].

Table 5 Key changes since the Draft 2026 ISP and their impacts in isolation

Key changes since the Draft 2026 ISP	Impact of each change in isolation
Included 15.8 GW/60.3 GWh of utility-scale storage, 4.8 GW of utility-scale solar, and 1 GW of wind capacity by 2029-30 that now meet the criteria to be classified as committed, anticipated[A], or policy-supported project as part of the January 2026 Generation Information update and recent tender results	Increased the utility-scale storage capacity early in the outlook period
Reflected known generation and storage developers' interests by including the connections pipeline until 2030 to increase the ISP's projected capacities' alignment with actual connection interests	Some utility-scale solar replaced by wind and utility-scale storage in the near-term
Improved the assumptions around the flexibility of coal by applying recent minimum continuous operating levels for coal plants which reflect more flexible operation of Victorian and New South Wales coal plants relative to historical flexibility, and relative to Queensland coal plants	Contributed to the deferral of transmission network augmentations
Updated consumer battery forecasts to capture the Federal Government's CHBP[B], increasing the forecast capacity of CER batteries by 6 GW in 2040 in *Step Change* and 12 GW in 2040 in *Accelerated Transition*. Also increased overall forecast VPP capacity, though participation rates remain the same as the 2026 Draft ISP	Reduction in flexible gas and wind capacity in the back of the outlook period, replaced by an increase in utility-scale solar
Revised the capital costs for new generation and storage technologies as per CSIRO's 2025-26 GenCost: Consultation draft publication[C], resulting in higher capital costs for open-cycle gas turbine (OCGT) and offshore wind and lower capital costs for utility-scale solar and pumped hydro	Increased utility-scale solar capacity in place of wind
Updated the Capacity Investment Scheme (CIS) trajectory based on the announcement of tenders 3 and 4[D] and updated the projects included in the New South Wales Electricity Infrastructure Investment (EII) generation and storage targets to align with the latest Generation Information dataset	The change to the CIS trajectory resulted in a delay to further utility-scale storage development and including previous projects in the New South Wales EII target resulted in a reduction in solar capacity required in New South Wales
Updated the constraint formulation of South Australia's 100% net renewable electricity target to correctly represent the policy	Slight reduction in thermal generation in South Australia
Updated the status of New England REZ Network Infrastructure Project to Anticipated from Actionable in the Draft 2026 ISP	Impact not separately identifiable, but reduced risk of the ISP rapidly becoming outdated
Unlinked the access of Borumba Pumped Hydro to the development of Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South)	Contributed to the ability to defer Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South)
Modelled Hunter-Central Coast REZ as two REZs to improve the network representation. This captured the REZ being located across Sydney, Newcastle and Wollongong (SNW) and Central New South Wales (CNSW) sub-regions. In addition, a new group constraint (HCC1) was introduced to limit new generation in this REZ without additional network augmentations.	Impact on results not separately identifiable, but improved network representation
Improved the generic New South Wales access right constraints with technology-specific limits for wind and solar technologies to ensure their installed capacity mix reflects the awarded access rights	Shifted utility-scale solar and wind capacity to REZs outside of the access scheme

[25] AEMO has published all inputs and assumptions in the 2026 ISP Inputs and Assumptions Workbook, including a change log of changes.

Key changes since the Draft 2026 ISP	Impact of each change in isolation
Included operating limits on oversized assets with access rights in Central-West Orana and South-West REZs in New South Wales to ensure their dispatches are capped at their awarded access-right capacities once they reach anticipated status	Impact was minor
Reflected the limit of five substation locations within Metropolitan Adelaide where utility-scale storages can be connected by constraining the amount of battery capacities that could be developed in the Central South Australia (CSA) sub-region	Impact not separately identifiable, but improved network capacity representation
Introduced total generation limits for hybrid generators to ensure co-located generation and storage assets do not exceed their registered site capacities as per the January 2026 update of AEMO's Generation Information dataset	In isolation, this resulted in a slight decrease in utility-solar capacity that was previously overstated, and an increase in wind capacity
Updated minimum capacity factors for gas generation based on the gas generation outcomes in 2026 GSOO[E] and updated daily gas limits based on updated gas consumption forecasts	Impact not separately identifiable, but improved accuracy
Updated gas fuel prices based on ACIL Allen's forecast[F]	In isolation this resulted in a small increase in generation from gas and reduction in wind capacity in the 2030s
Modelled Brisbane Area 275 kV Reinforcement as an explicit augmentation option to the flow path between Central Queensland and Southern Queensland rather than assuming to be going ahead as per the Draft 2026 ISP, therefore reducing the transfer capacity of Central Queensland to Southern Queensland flow path specified as 1,100 megawatts (MW) in the Draft 2026 ISP	Impact not separately identifiable, but improved representation of network capacity
Implemented a monthly hydrogen demand targets for electrolysers instead of weekly to improve flexibility of usage in response to stakeholder feedback that the utilisation factor was high	Reduced electrolyser utilisation by approximately 10% on average
Corrected vehicle-to-grid (V2G) charging and discharging efficiencies from 83.7% to 92.2% and lowered maximum state of charge to 85% to align with the values stated in the 2025 IASR	Slight reduction of utility-scale solar capacity
Corrected battery auxiliary loads to align with the values stated in the 2025 IASR	Slight reduction in utility-scale storage generation as a percentage is required for use in-house

A. Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated. Projects with known timing, satisfying all five of the commitment criteria are assigned a commitment status classification of committed. More information can be found in the Generation Information publication at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
B. See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.
C. At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.
D. See https://asl.org.au/tenders/cis-tender-3-nem-dispatchable.
E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf?rev=58e84053c8d240a487cf274c91ebd284&sc_lang=en.
F. See Wholesale natural gas prices for AEMO at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf?rev=91c2467e5f3c4aa1b9a2b2c6c75a976a&sc_lang=en.

Overall, compared to the Draft 2026 ISP, there is a $4 billion increase in net market benefits in *Step Change* driven by the following:

- Significantly more generation and storage projects, most of them in REZs, have reached higher development certainty and progressed to committed or anticipated status. Projects in the connections pipeline are therefore developed earlier in the modelling than projects in locations that do not yet have proponents. This reflects stakeholder feedback to give greater weight to projects that have already begun the application process. As these projects are treated as more certain in the modelling, the benefits of transmission that supports their efficient dispatch have increased.
- Updated cost assumptions have widened the difference in total system cost between the CDPs and the 'no transmission' counterfactual development path. Lower capital costs for utility-scale solar in CSIRO's Draft 2025–26 GenCost report reduce total system costs across all CDPs. At the same time, higher capital costs for flexible gas, which is mostly located near demand centres, increase costs in the 'no transmission' counterfactual, which requires more of this capacity to be built.

- Improved modelling of southern gas limits informed by the 2026 GSOO[26], which affect the ability to build flexible gas in the Sydney, Newcastle and Wollongong (SNW) sub-region, has increased the benefits of transmission projects that improve reliability of electricity supply to the region, including the Sydney Ring projects.
- Improved modelling of the link between Borumba Pumped Hydro and Central Queensland to Southern Queensland Expansion (previously known as Queensland SuperGrid South) has allowed Central Queensland to Southern Queensland Expansion to be deferred, reducing total system costs. Similarly, improved modelling of coal plant operational flexibility across the NEM has allowed some transmission assets, such as QNI Connect, to be deferred.

Together, these changes widen the gap in total system cost between the CDPs and the 'no transmission' counterfactual development path, increasing the benefits of transmission.

[26] See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gas-statement-of-opportunities.pdf?rev=58e84053c8d240a487cf274c91ebd284&sc_lang=en.

A6.4 Step 1: Determining least-cost development paths for each scenario

A6.4.1 Process of finding the least-cost development paths

The first stage in the CBA process was to determine the least-cost DP which contains the optimal mix of generation, storage, and network developments that would maximise the market benefits described in Section A6.2.3 for each individual scenario. This was based on testing over 1,000 permutations of network development options and timings, and on the impact that network developments have on generation and storage outcomes. As all the classes of market benefit considered relate to cost savings, the DP that maximises net market benefit is the least-cost DP. Therefore, in practice, the total system costs of all DPs (calculated as an NPV of the future streams of eligible system costs) were compared to identify the DP that minimises the total system costs, thereby maximising market benefits in the long-term interest of consumers.

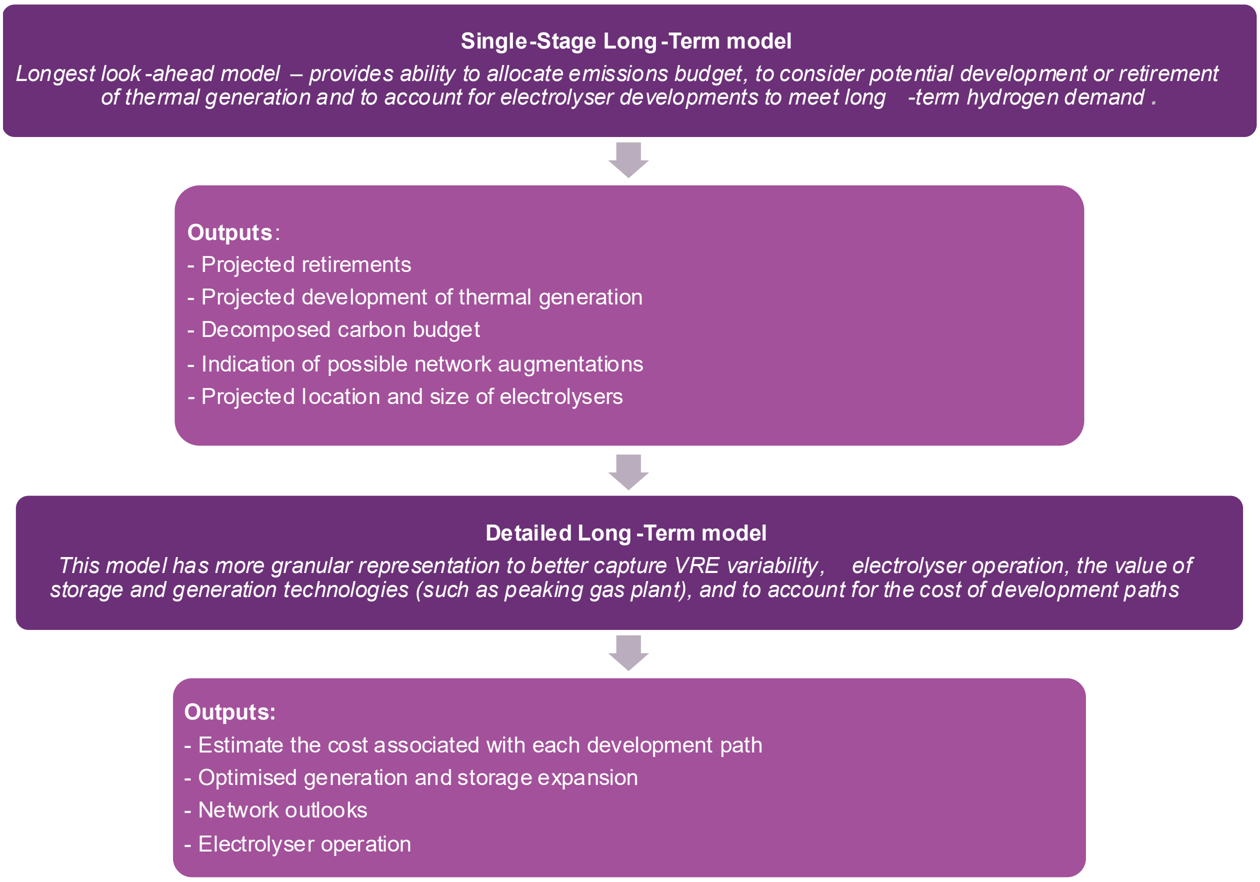
The process for searching for the least-cost DP in each scenario used two interacting capacity outlook models to address different aspects of the long-term optimisation – the Single-Stage Long-Term (SSLT) model and the Detailed Long-Term (DLT) model:

- **The SSLT model** provides the longest look-ahead (at lower granularity), optimising the total system cost over the entire outlook period in one step. This allows consideration of emission budgets, potential development or retirement of thermal assets, and electrolyser development to supply hydrogen production requirements. While network, generation and storage expansion is fully co-optimised in this step, the SSLT model lacks the granularity required to precisely identify which combination of discrete network projects, and their timings, will best meet the needs of consumers. In effect, the SSLT modelling identifies the network flow paths and REZ networks that do or do not indicate a need for augmentation over the outlook period, as well as the network projects that may meet those needs, to be examined in greater detail in the ISP's subsequent modelling.
- **The DLT model** divides the outlook period into multiple steps (each with a shorter outlook period than the entire outlook period) that are then optimised sequentially. This compartmentalised approach provides capability to provide a more granular representation of each day's demand requirement and supply availability from renewable and energy-limited plant. The DLT model applies the SSLT insights, such as emissions budgets, generator retirement decisions, and development of high-utilisation fossil-fuelled generation.

The interaction between these models is illustrated in **Figure 5** and further explained in the *ISP Methodology*[27].

[27] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/isp-methodology.

Figure 5 Overview of the ISP capacity outlook model



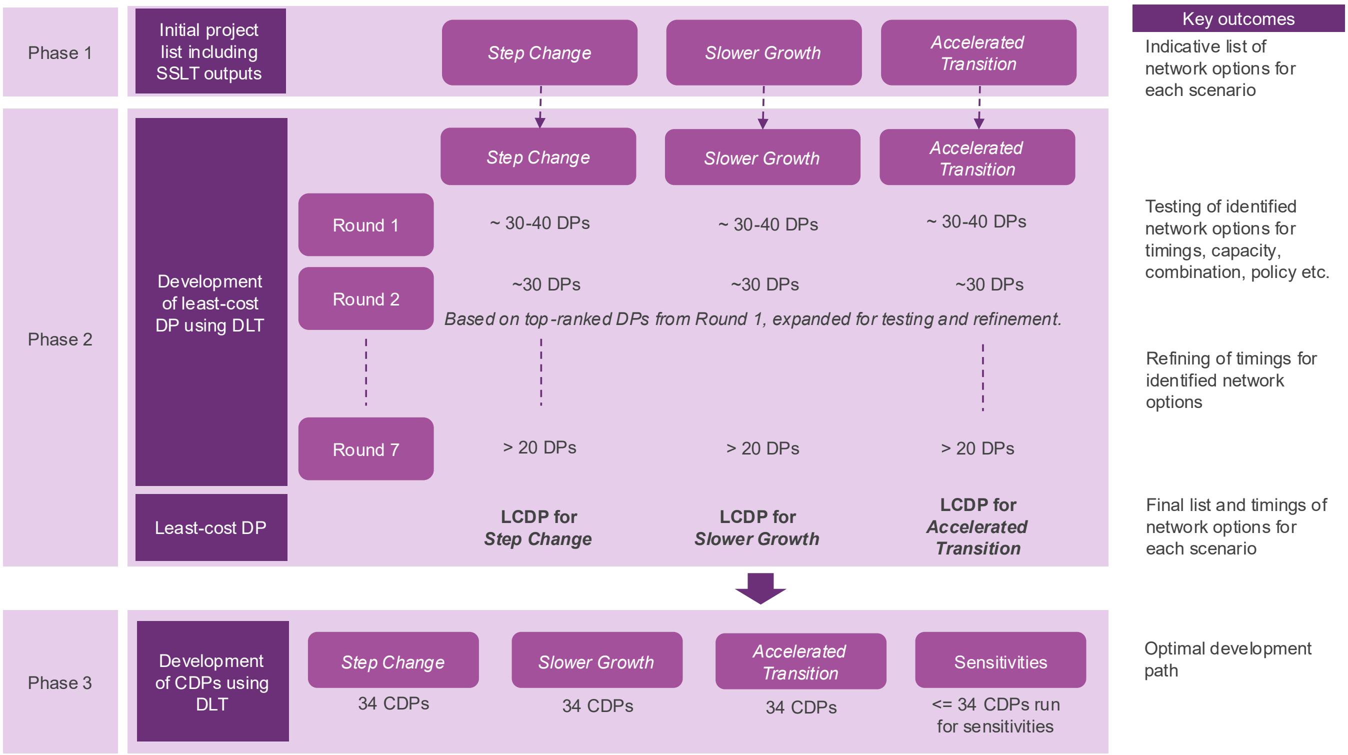
The outputs from both models were used to identify the least-cost DPs for each scenario which are, in turn, used as the basis for developing the full set of CDPs that are further investigated in the cost-benefit analysis phase of the modelling. The methodology and principles behind the search for least-cost DPs and CDPs are covered in detail in Section 6 of the *ISP Methodology*[28]. The process is illustrated in **Figure 6** and can be broken down into three phases:

- Phase 1 was to develop the initial and broad list of projects that would be considered for further investigation in successive phases. This includes identification of transmission projects that may potentially be actionable under each of the three ISP scenarios using the SSLT model and other approaches (which are further detailed in subsequent sections).
- Phase 2 was the search for potentially actionable projects that form part of the least-cost DPs using the DLT model and the outcomes of Phase 1. This phase identified the potentially actionable projects and project combinations that would form the least-cost DP for each scenario using multiple runs of the DLT. Each run applied a 'branch and bound' technique to progressively identify, or eliminate, projects and project combinations that would (or would not) form part of the least-cost DP. The least-cost DPs and corresponding potentially actionable projects resulting from this phase subsequently informed the first three CDPs that were investigated in the third phase.
- Using the outcomes of Phase 2, additional CDPs were then developed. The potentially actionable transmission projects within the CDP were treated as given, and the modelling optimised all other investment decisions, including generation,

[28] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp%20methodology/isp-methodology-june-2025.pdf?rev=e88a1f1bbeef447ba27692b785069a0a&sc_lang=en.

storage, distribution, and future transmission, to identify the least-cost developments and total system costs for that scenario, conditional on those transmission projects being developed. Details of this modelling are further described in Section A6.5.

Figure 6 Process for development of least-cost DPs and CDPs for the 2026 ISP



The first two phases, used for identifying the least-cost DPs, are further detailed in the following sections. Subsequent validation of the capacity outlook modelling outcomes was also conducted using AEMO's time-sequential modelling, as described in the *ISP Methodology*. The insights from this modelling are available in Appendix A4 System Operability.

Phase 1: Developing the initial projects list for further investigation in the DLT

The purpose of this phase was to identify the initial list of projects and combinations of projects that should be further investigated at a more granular detail in the second phase if they provide lower system costs. The initial projects list, composed of four kinds of network projects that may potentially be actionable, was developed by the following approaches:

- **Outputs from the SSLT model** – the SSLT model is the first screening tool used to identify the linearised[29] network options that are needed to minimise the total system cost for each scenario. With a linearised network representation, the SSLT model can build a percentage of a transmission augmentation in a given year rather than needing to make a choice of either building or not building the augmentation (which is computationally more burdensome). The SSLT helps identify the timing and scale of capacity requirements for each of the selected linearised network options. It also

[29] Linearised build decisions are applied to allow incremental development of network options and not restrict development of those options to just all or nothing. By doing so, the simulations are more tractable.

identifies flow paths and REZ networks that do not need augmentation, for which network options are not considered in succeeding phase. The year in which the installed capacity of a network option reaches more than 50% of the stated capacity acts as an indication of the year for further testing the timings in Phase 2 for identifying the least-cost DPs.

The identified timing needs further investigation in the succeeding phase, as the SSLT model lacks the granularity to adequately capture the variability of VREs, electrolyser operations, and the value of storage and generation technologies such as peaking gas plants.

- **Existing actionable projects** – in addition to the projects identified in the SSLT model, AEMO also included projects that were considered actionable in the 2024 ISP or the Draft 2026 ISP in the initial projects list, regardless of whether the SSLT provided any indication that the project should be further investigated in the DLT or not. This ensures the actionability of existing actionable projects is retested in successive ISPs, consistent with the AER's CBA Guidelines[30].
- **Projects that are impacted by other generation and storage development or policies** – AEMO also included those projects that are needed to meet policy or that are relevant to expected generation and storage developments in the NEM in the initial projects list.

> An example of a transmission project relevant to policy is the Gippsland offshore wind transmission options (developed in three stages – Stage 1, Stage 2 – Phase 1 and Stage 2 – Phase 2) which are necessary to allow connection of offshore wind capacity to meet the Victorian Offshore Wind Target of 9 GW by 2039-40.

- **Other projects that are in geographical and electrical proximity to projects already included in the initial projects list** – some transmission projects deliver more synergies when they are delivered together due to their geographical proximity to each other.

> Examples of projects with geographical and electrical proximity are the Switching Station Near Wondalga and Sydney Ring South which both allow higher renewable generation in Central and Southern New South Wales REZs to supply Sydney, Newcastle and Wollongong load centres. This set of projects is considered in the initial projects list individually and collectively.

Phase 2: Identifying potential actionable projects

Phase 1 provided the initial list of network options that should be considered in each scenario. The network options in the initial projects list were then further tested in the DLT capacity outlook model.

In Phase 2, the search for the least-cost DP involved testing the network options identified in Phase 1 through an iterative process and multiple rounds of the DLT capacity outlook model, as shown above in **Figure 3** and explained below. For every round, the decision on which set of projects to be investigated further in succeeding rounds was based on the rankings of DPs according to their total system costs. The projects featured in the higher-ranked DPs that have similar total system costs in magnitude were further investigated in succeeding rounds to progressively refine the DP selection.

Round 1: Assessing the base case and alternative development paths

In the first round of iteration, a base (starting case) DP was created for each scenario based on the identified network options from the preceding phase 1. The base DP consisted of a network build schedule featuring all the initial network

[30] See https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines/current-cba-guidelines, p.18.

options' full development at their EISDs. DPs were then created around the base DP by adding or pruning network options in the initial projects list using a 'branch and bound' algorithm[31] wherein the following was tested:

a) network and non-network options delivered at different timings such as outside the EISD, or no development of the identified option within the outlook period,
b) staging of network capacity such as testing in stages or full capacity,
c) alternative options and non-network options for the same flow paths with different capacity and costs,
d) any combination of network options based on the proximity and timings of transmission flow path or REZ augmentation, or any potential impact of one on any other,
e) testing network options to support policy, and
f) for projects previously identified as actionable in the previous ISP, alternative timings being at the proponent's timing, at the end of the actionable window, or thereafter.

Example of testing for a network option in development paths

The Gladstone Project (Central Queensland – Gladstone Grid [CQ-GG] Option 2) was previously identified as actionable in the 2024 ISP. It improves supply to the Gladstone Grid sub-region as coal generation retires by raising the transmission capacity from Central Queensland to Gladstone Grid by 2,600 megawatts (MW). In Phase 1 analysis for the 2026 ISP, the SSLT results identified that this network augmentation remained beneficial. CQ-GG Option 2 was therefore included in the initial projects list for Phase 2.

Since it was previously actionable in the 2024 ISP, AEMO tested its timings at both its EISD (1 March 2029) and the year after the end of its actionable window (1 March 2033) as per the *ISP Methodology*. In addition to this, the CQ-GG Option 2 project delivery at EISD and at delayed timing (outside the actionable window) were also tested along with (and also substituted by) different combinations of other projects such as CQ-GG Option 3, Southern Queensland (SQ)-CQ Option 2, SQ-CQ Option 5, SQ-CQ Option 7, CQ-Northern Queensland (NQ) Option 3, CQ-NQ Option 4, and Northern New South Wales (NNSW)-SQ Option 2. The combination was selected such that it adequately represented the projects that may influence intra- and inter-regional transmission flows and capacity builds in the NEM.

More than 100 DPs were investigated across scenarios in Round 1. This initial set of DPs was informed by results from Phase 1 and was meant to cast the net wider to check different combinations of network projects that could be included in the least-cost DP of each scenario. As such, the exact timing of each project was refined in the next rounds.

From the initial set of DPs, the advantage of one DP over another was assessed through the total system cost outcomes of each DP. The DP with the lowest total system cost then became the base DP for the next round for each scenario, complemented by other DPs in the top ranked DPs for which the resulting total system cost was sufficiently low-cost and statistically close to the least-cost DP, as well as variations in the timings of the projects featured in these DPs.

The network projects that featured in DPs with relatively high total system costs (that is, those projects that may not be used sufficiently if built) were dropped and not further examined in succeeding rounds. For example, the development of the West and North Victoria (WNV) – South East South Australia (SESA) Option 1 and V9 (Southern Ocean) Option 1 flow

[31] More details on this at https://www.fico.com/fico-xpress-optimization/docs/dms2021-03/solver/optimizer/HTML/chapter4_sec_section4003.html.

path augmentations in *Step Change* delivered negative net market benefits in Round 1, and hence were not tested in succeeding rounds.

Round 2 and onwards: Refining the network options, combinations, and timings

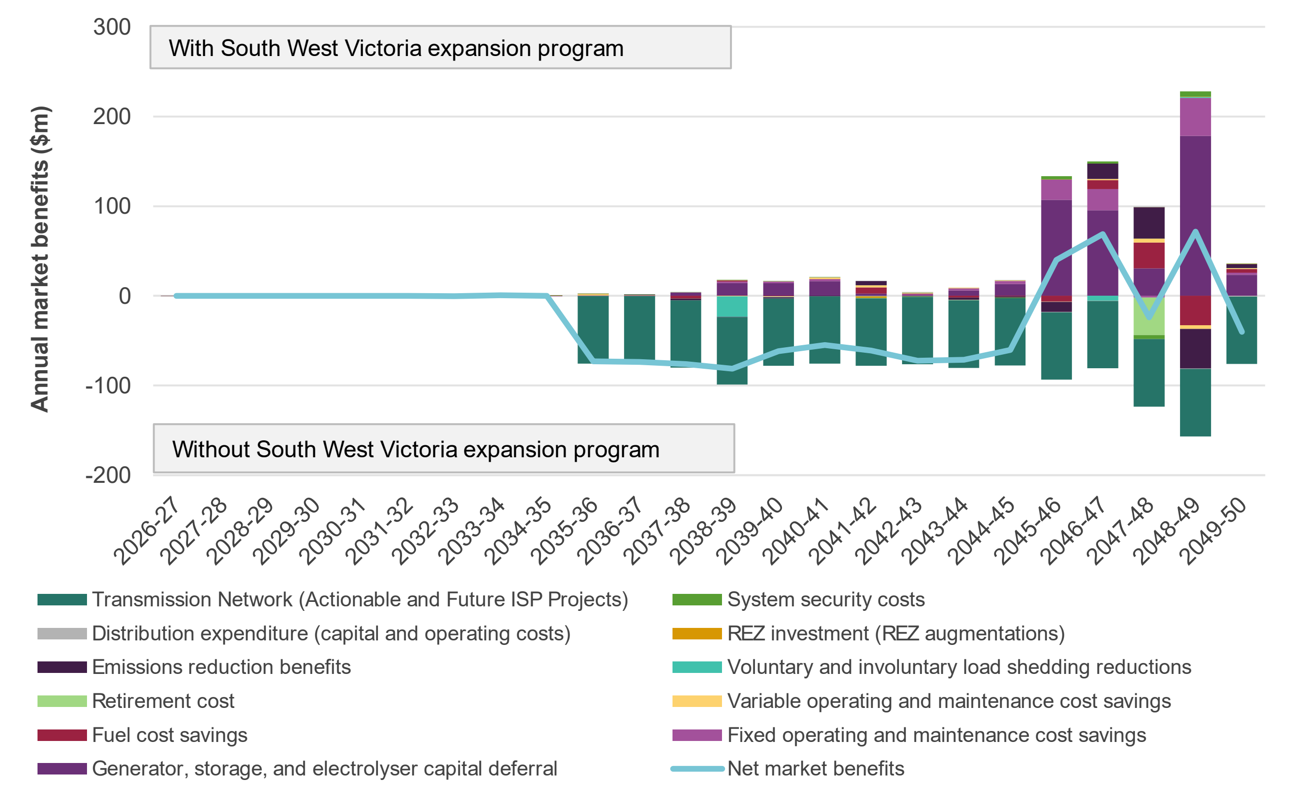
Round 2 and onwards were iterations undertaken to refine network option timings and combinations. The DP with lowest system cost compared to all the other DPs in Round 1 acted as the starting DP for Round 2. Around this new starting case, additional DPs were created following a similar process of crafting the set of DPs in Round 1 but only considering the projects that made it through to the second round and excluding projects that did not demonstrate net market benefits.

As projects were whittled down through this iterative process, more focus was given to the timings of delivery of network projects. The following example shows how the timing of a network option was ascertained.

Example of identifying timings for a network option

The analysis to determine the optimal timing for South West Victoria expansion program in *Step Change* was based on **Figure 7**. The figure shows the annual market benefit (above 0 on the Y-axis) of having the South West Victoria expansion program in 2035-36 compared to not having the network option at all. Positive values show benefits of the network option, whereas negative values show a benefit in not proceeding with the network option. Overall, the project results in negative net market benefits of $220 million if delivered in 2035-36 compared to not having it at all. However, the annual market benefits become positive at two points (in 2045-46 and in 2048-49), which suggests that there are benefits from having the South West Victoria expansion program at these points. Therefore, the timings for this network option in the following round were tested in 2045-46 and 2048-49 to ascertain which of the two timings was optimal and would facilitate the higher overall benefits to NEM.

Figure 7 Annual relative market benefits of South West Victoria expansion program in *Step Change* (2035-36)



Project timings were typically tested at the project's EISD, beyond the actionable window, at points where annual benefits became positive in previous simulations (such as those identified in the example above), and a 'no transmission' counterfactual where it is not built within the outlook period.

DPs were dropped from further analysis once there was sufficient evidence that there were no benefits derived from a network option being tested at different timings (that is, the annual market benefit line in the previous chart stays below zero throughout the outlook period).

In the example above, if the DP that featured the South West Victoria expansion program had no cross-over (the point in which the net market benefits line crosses the x-axis) and stayed negative until the end of the outlook period, this would indicate that the project had no net market benefits under that scenario. It would then be dropped as a candidate network option for the least-cost DP and would not be tested in successive rounds.

If, however, the DP that featured delivery of the South West Victoria expansion program showed positive net market benefits throughout the entire outlook period (cross-over from its entry year), its delivery – together with the delivery of adjacent network options such as Victoria – New South Wales Interconnector West (VNI West) and Switching Station Near Wondalga at their EISDs (for example) – would form another DP to be tested in the next round. The choice of which network project(s) to combine with the South West Victoria expansion program and be tested in the next round would be based on the results for other DPs that feature those other projects. That is, AEMO also assesses the case for other projects, such as VNI West and Switching Station Near Wondalga, and checks that those projects provide net market benefits individually.

If that combination of three projects proved to be economic, AEMO would test delivery of those projects together with delivery of VNI West at its EISD in the next round. If that also proved to be economic, AEMO would test delivery of those projects together with Sydney Ring North (Hunter Transmission Project) in the next round. If those five projects continued to provide net market benefits, AEMO would add another project for the next round, and so on.

However, if those five projects were not economic, AEMO would take Sydney Ring North (Hunter Transmission Project) out from contention and would test the next project that could be part of the least cost-DP for that scenario.

Generally, when implementing the next round, the least-cost DP for each scenario in any round was used as the base case for the next round, with new alternative DPs created. The result of that next round became the starting point for the proceeding round, with this process continuing until only one least-cost DP for each scenario was identified. For the 2026 ISP, this took seven rounds.

The following sections detail the least-cost development paths AEMO arrived at for each scenario following the conclusion of the process described above, as well as their benefits compared to a 'no transmission' counterfactual DP with no transmission augmentations beyond committed and anticipated projects. These least-cost development paths form the basis of the collection of CDPs, as described in Section A6.5.

A6.4.2 Least-cost development path for *Step Change*

Step Change presents a scenario where Australia achieves government policy objectives and transitions the energy system to support limiting global temperature rise below 2°C, with moderate economic and population growth, strong consumer investment in electrification and CER, and material new loads from transport and industry but limited domestic hydrogen industry growth.

The pace of the transition in *Step Change* is underpinned by generation, storage, and network developments that form the least-cost development path for the scenario. For transmission networks, most actionable projects in the least-cost DP had been identified as actionable in the 2024 ISP along with some newly actionable projects that upgrade the transfer capacities to major load centres such as Sydney, Newcastle and Wollongong and the Greater Melbourne and Geelong areas. Some of the projects, like VNI West, provide additional capacity to share resources between regions and access to major utility-scale storage developments like Snowy 2.0.

Table 6 presents the timings of relevant network development options in the least-cost DP for *Step Change* and a subset of relevant alternative projects that were found optimal in the least-cost DPs of other scenarios, but were ultimately not found to deliver benefits within the outlook period under this scenario.

Table 6 Network development schedule in the least-cost development path for *Step Change*

Network option	EISD	Least-cost DP
Transmission network development schedule		
Central to North Queensland Reinforcement (Stage 1)	**2029-30[A]**	2037-38
Central to North Queensland Reinforcement (Stage 2)	**2033-34**	2042-43
Gladstone Project	**2028-29**	2028-29
Central Queensland to Gladstone Grid Expansion - line rebuild option	**2031-32**	
Brisbane Area 275 kV Reinforcement	**2031-32**	2031-32
Auburn River Switching Station[A]	**2031-32**	
Central Queensland to Southern Queensland Expansion[B]	**2031-32**	
Queensland – New South Wales Interconnector (QNI) Connect	**2033-34**	2041-42
Sydney Ring North (Hunter Transmission Project)	**2029-30**	2029-30
Sydney Ring South power flow control option	**2030-31**	2030-31
Sydney Ring South – 500 kV option (Stage 1)	**2033-34**	2033-34
Sydney Ring South – 500 kV option (Stage 2)	**2033-34**	2033-34
Central-West Orana REZ Expansion	**2032-33**	2032-33
Switching Station Near Wondalga	**2030-31**	2030-31
Victoria – New South Wales Interconnector West (VNI West)	**2031-32**	2031-32
Western Victoria Reinforcement program	**2028-29**	2028-29
South West Victoria expansion program	**2033-34**	2045-46
Eastern Victoria Reinforcement Option 1	**2031-32**	2033-34
Eastern Victoria Reinforcement Option 2	**2031-32**	
Gippsland Offshore Wind Transmission Stage 1	**2031-32**	2031-32
Gippsland Offshore Wind Transmission Stage 2 – Phase 1	**2033-34**	2033-34
Gippsland Offshore Wind Transmission Stage 2 – Phase 2	**2038-39**	2038-39
Project Marinus Stage 2	**2034-35**	2046-47
North West Tasmania REZ option	**2030-31**	2030-31
Central Highlands REZ option	**2030-31**	
Heywood Interconnector Upgrade	**2031-32**	
SESA-CSA Transmission Upgrade	**2029-30**	
Northern Transmission Project	**2029-30**	
Distribution network development opportunities		
Hunter-Central Coast REZ Expansion	**2030-31**	
Dubbo Distribution Project (Option 1)	**2030-31**	2032-33
Dubbo Distribution Project (Option 2a)	**2031-32**	2033-34

A. The project proponent has advised that the EISD for this project has changed since the completion of the ISP modelling. See Appendix A5 for more details.
B. Part of the Central Queensland to Southern Queensland Expansion project.
Note: Light teal indicates that a project is delivered within its actionable window, and empty rows mean the corresponding projects are not delivered within the outlook period under this scenario.

Benefits of the least-cost DP compared with the 'no transmission' counterfactual DP in *Step Change*

Table 7 provides a breakdown of the classes of market benefits delivered by the least-cost DP in *Step Change* compared with the 'no transmission' counterfactual DP where no new major transmission is developed across the NEM[32]. Savings in generator capital costs and fuel costs from avoided development and operation of flexible gas and offshore wind in the absence of transmission augmentation represent most of the net market benefits in *Step Change*.

Figure 8 shows that the annual net market benefits of the least-cost DP in *Step Change* compared with the 'no transmission' counterfactual DP come primarily from avoided generator capital expenditure and fuel cost savings.

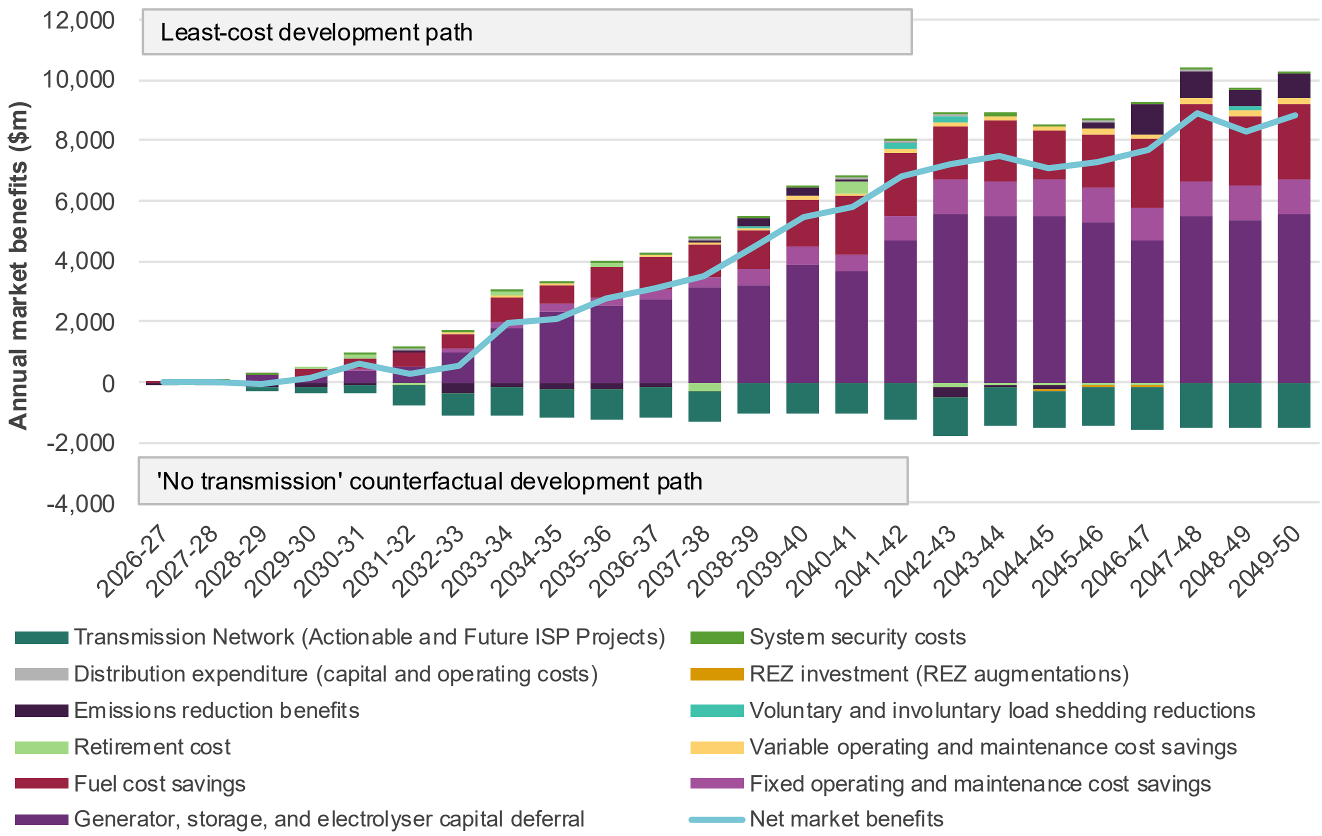
Under the 'no transmission' counterfactual DP, flexible gas, including using carbon capture storage, is required in the latter years to ensure energy supply can be met, while also meeting government policies, with lesser ability to develop renewable generation by upgrading the transmission network. To ensure that emissions reduction targets can still be achieved, several black coal-fired generators in New South Wales and Queensland are retired earlier which results in up to 5 GW of wind capacity development being brought forward into existing REZs with available capacity. Up to 8 GW of additional utility-scale storage is required as well to provide firming capacity.

Table 7 Net market benefits of the least-cost DP compared with the 'no transmission' counterfactual DP, *Step Change*

Class of market benefit	Net market benefit (NPV, $ million)
Generator, storage and electrolyser capital deferral	22,933
Fixed operating and maintenance cost savings	3,748
Fuel cost savings	9,428
Variable operating and maintenance cost savings	603
Retirement cost	142
Voluntary and involuntary load shedding reductions	167
Emissions reduction benefits	15
REZ investment (REZ augmentations)	-148
Distribution expenditure (capital and operating costs)	130
System security costs	365
Gross market benefits	**37,383**
Transmission Network (Actionable and Future ISP Projects)	-7,618
Total net market benefits	**29,765**

[32] Neither flow path nor REZ transmission augmentations are allowed in this development path. This does not include connecting assets for new plants which will continue to connect to the existing network.

Figure 8 Net market benefits of the least-cost DP relative to the 'no transmission' counterfactual DP in *Step Change*



The development of new generation capacities in REZs will often require new transmission networks to enable renewable generation connections at scale. As the transmission network is not expanded in the 'no transmission' counterfactual DP, lesser generation developments in REZs will have to be complemented by more expensive alternatives such as flexible gas with CCS to reduce carbon emissions. Development and operation of this flexible gas results in fuel cost increases and requires further carbon storage infrastructure development[33]. See Appendix A10 for insights on the capability of the gas system to supply gas in *Step Change*.

In the 'no transmission' counterfactual DP, the retirement of the Gladstone Power Station would cause significant system reliability risks in Gladstone Grid as there is insufficient local generation options in the sub-region, due to gas supply limitations. AEMO does not consider this credible, hence the gas supply limit applied to flexible gas development in Gladstone Grid was assumed to be lifted.

[33] While carbon capture costs are included in the generator capital costs for flexible gas with CCS, the costs for supporting infrastructure in the gas system and carbon storage are not included in the cost categories, or market benefits classes, of the CBA assessment.

A6.4.3 Least-cost development path for *Slower Growth*

Slower Growth features a future where Australia reaches net zero emissions by 2050 amid weak economic conditions, slower technology cost declines, and more limited consumer and commercial business capacity to support the transition in a more challenging investment environment.

This scenario therefore explores over-investment risks by featuring lower overall growth in energy consumption and explicit closures of large energy-intensive industrial loads. This generally leads to less need for network expansion, generation development, and storage development than *Step Change*, although the scenario still is designed to accommodate all eligible government policies. **Table 8** shows timings of the network development projects in the least-cost DP for *Slower Growth*.

Table 8 Network development schedule in the least-cost development path for *Slower Growth*

Network option	EISD	Least-cost DP
Transmission network development schedule		
Central to North Queensland Reinforcement (Stage 1)	2029-30[A]	
Central to North Queensland Reinforcement (Stage 2)	2033-34	2049-50
Gladstone Project	2028-29	2028-29
Central Queensland to Gladstone Grid Expansion - line rebuild option	2031-32	
Brisbane Area 275 kV Reinforcement	2031-32	2037-38
Auburn River Switching Station[A]	2031-32	
Central Queensland to Southern Queensland Expansion[B]	2031-32	
Queensland – New South Wales Interconnector (QNI) Connect	2033-34	2040-41
Sydney Ring North (Hunter Transmission Project)	2029-30	2029-30
Sydney Ring South power flow control option	2030-31	2030-31
Sydney Ring South – 500 kV option (Stage 1)	2033-34	2037-38
Sydney Ring South – 500 kV option (Stage 2)	2033-34	2037-38
Central-West Orana REZ Expansion	2032-33	2039-40
Switching Station Near Wondalga	2030-31	2033-34
Victoria – New South Wales Interconnector West (VNI West)	2031-32	2031-32
Western Victoria Reinforcement program	2028-29	2039-40
South West Victoria expansion program	2033-34	
Eastern Victoria Reinforcement Option 1	2031-32	
Eastern Victoria Reinforcement Option 2	2031-32	2038-39
Gippsland Offshore Wind Transmission Stage 1	2031-32	2033-34
Gippsland Offshore Wind Transmission Stage 2 – Phase 1	2033-34	2035-36
Gippsland Offshore Wind Transmission Stage 2 – Phase 2	2038-39	2038-39
Project Marinus Stage 2	2034-35	2034-35
North West Tasmania REZ option	2030-31	2032-33
Central Highlands REZ option	2030-31	
Heywood Interconnector Upgrade	2031-32	
SESA-CSA Transmission Upgrade	2029-30	
Northern Transmission Project	2029-30	
Distribution network development opportunities		
Hunter-Central Coast REZ Expansion	2030-31	
Dubbo Distribution Project (Option 1)	2030-31	
Dubbo Distribution Project (Option 2a)	2031-32	

A. The project proponent has advised that the EISD for this project has changed since the completion of the ISP modelling. See Appendix A5 for more details.
B. Part of the Central Queensland to Southern Queensland Expansion project.
Note: Light teal indicates that a project is delivered within its actionable window, and empty rows mean the corresponding projects are not delivered within the outlook period under this scenario.

Benefits of the least-cost development path compared with the ‘no transmission’ counterfactual DP in *Slower Growth*

Table 9 presents the net market benefits of the least-cost development path in *Slower Growth* compared to the ‘no transmission’ counterfactual development path, where no new major transmission is developed across the NEM[34]. The main sources of benefits are capital deferral in generation, storage assets, fuel cost savings, and emission reduction benefits. Although the least-cost development path develops various transmission developments before 2033-34, the primary benefits to defer more costly generation and storage alternatives accumulate most significantly after 2033-34. Across the entire outlook period, transmission investments also accrue material benefits from fuel cost savings and emission reduction benefits.

Table 9 Net market benefits of the least-cost DP compared with the ‘no transmission’ counterfactual DP, *Slower Growth*

Class of market benefit	Net market benefit (NPV, $ million)
Generator, storage and electrolyser capital deferral	7,373
Fixed operating and maintenance cost savings	1,142
Fuel cost savings	4,585
Variable operating and maintenance cost savings	280
Retirement cost	30
Voluntary and involuntary load shedding reductions	14
Emissions reduction benefits	4,438
REZ investment (REZ augmentations)	-39
Distribution expenditure (capital and operating costs)	22
System security costs	159
Gross market benefits	**18,004**
Transmission Network (Actionable and Future ISP Projects)	-7,199
Total net market benefits	**10,805**

The least-cost development path allows for better sharing of electricity across the NEM through increased capacity of transmission flow paths, whereas the ‘no transmission’ counterfactual DP requires further development of flexible gas and utility-scale batteries (mostly in the Sydney, Newcastle and Wollongong and Greater Melbourne and Geelong load centres).

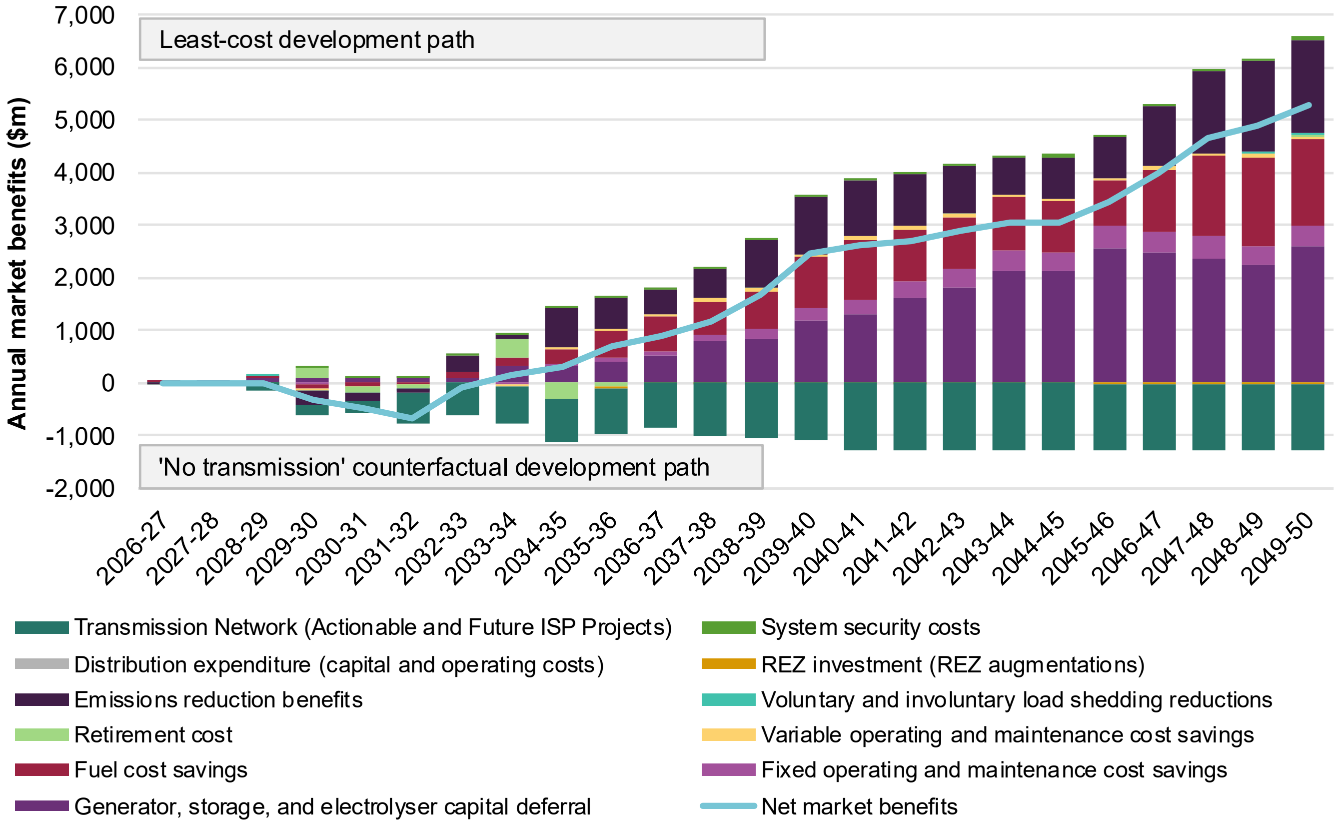
In this scenario, the ‘no transmission’ counterfactual DP requires expansion of mid-scale generation and storage[35] capacity, which is developed across all states except in Queensland, but particularly in New South Wales, as this technology does not depend on further augmentation of the transmission network. In Victoria, the ‘no transmission’ counterfactual DP demonstrates that without transmission upgrades there would be high levels of curtailment of offshore wind, and additional onshore wind across the NEM would be required to service customer needs if that generation was curtailed. The annualised net market benefits of the least-cost development path compared to the counterfactual are shown in **Figure 9**.

[34] Neither flow path nor REZ transmission augmentations other than anticipated and committed are allowed in this counterfactual. This does not include connecting assets for new plants which will continue to connect to the existing network.

[35] Refers to utility-scale solar installations that are connected at the high-voltage section of the distribution network and are assumed to be limited to 30 MW.

In the 'no transmission' counterfactual DP, the retirement of the Gladstone Power Station would cause significant system reliability risks in Gladstone Grid sub-region as there are insufficient local generation options in the sub-region due to fuel supply limitations. AEMO does not consider this credible, hence the gas supply limit applied to flexible gas development in Gladstone Grid was assumed to be lifted in this case.

Figure 9 Net market benefits of the least-cost development path relative to the 'no transmission' counterfactual DP in *Slower Growth*



A6.4.4 Least-cost development path for *Accelerated Transition*

Accelerated Transition features faster economic growth and stronger commitment to decarbonise the economy which drives rapid energy sector transformation through electrification, green commodity production, and high consumer uptake of CER and increased CER coordination.

The scenario therefore features the quickest rate of transformation, which, in turn, leads to greater need for the development of infrastructure compared with *Step Change*.

Table 10 presents the timing of various transmission expansion options in the least-cost DP for *Accelerated Transition*.

Table 10 Network development schedule in the least-cost development path for *Accelerated Transition*

Network option	EISD	Least-cost DP
Transmission network development schedule		
Central to North Queensland Reinforcement (Stage 1)	**2029-30[A]**	2029-30
Central to North Queensland Reinforcement (Stage 2)	**2033-34**	2035-36
Gladstone Project	**2028-29**	2028-29
Central Queensland to Gladstone Grid Expansion - line rebuild option	**2031-32**	2035-36
Brisbane Area 275 kV Reinforcement	**2031-32**	2031-32
Auburn River Switching Station[A]	**2031-32**	2040-41
Central Queensland to Southern Queensland Expansion[B]	**2031-32**	2047-48
Queensland – New South Wales Interconnector (QNI) Connect	**2033-34**	2041-42
Sydney Ring North (Hunter Transmission Project)	**2029-30**	2029-30
Sydney Ring South power flow control option	**2030-31**	2030-31
Sydney Ring South – 500 kV option (Stage 1)	**2033-34**	2033-34
Sydney Ring South – 500 kV option (Stage 2)	**2033-34**	2033-34
Central-West Orana REZ Expansion	**2032-33**	2032-33
Switching Station Near Wondalga	**2030-31**	2030-31
Victoria – New South Wales Interconnector West (VNI West)	**2031-32**	2031-32
Western Victoria Reinforcement program	**2028-29**	2028-29
South West Victoria expansion program	**2033-34**	
Eastern Victoria Reinforcement Option 1	**2031-32**	2033-34
Eastern Victoria Reinforcement Option 2	**2031-32**	
Gippsland Offshore Wind Transmission Stage 1	**2031-32**	2031-32
Gippsland Offshore Wind Transmission Stage 2 – Phase 1	**2033-34**	2033-34
Gippsland Offshore Wind Transmission Stage 2 – Phase 2	**2038-39**	2038-39
Project Marinus Stage 2	**2034-35**	2034-35
North West Tasmania REZ option	**2030-31**	2030-31
Central Highlands REZ option	**2030-31**	2030-31
Heywood Interconnector Upgrade	**2031-32**	2042-43
SESA-CSA Transmission Upgrade	**2029-30**	2042-43
Northern Transmission Project	**2029-30**	2041-42
Distribution network development opportunities		
Hunter-Central Coast REZ Expansion	**2030-31**	2030-31
Dubbo Distribution Project (Option 1)	**2030-31**	2030-31
Dubbo Distribution Project (Option 2a)	**2031-32**	2031-32

A. The project proponent has advised that the EISD for this project has changed since the completion of the ISP modelling. See Appendix A5 for more details.
B. Part of the Central Queensland to Southern Queensland Expansion project.
Note: Light teal indicates that a project is delivered within its actionable window, and empty rows mean the corresponding projects are not delivered within the outlook period under this scenario.

Benefits of the least-cost development path compared with the ‘no transmission’ counterfactual DP in *Accelerated Transition*

Table 11 provides a breakdown of the classes of market benefits delivered by the least-cost DP compared with the ‘no transmission’ counterfactual DP in *Accelerated Transition*. It shows that avoided generator capital costs and avoided fuel costs represent most of the gross market benefits in *Accelerated Transition*. The net market benefits of developing the transmission network in this scenario amount to $42.7 billion.

Table 11 Net market benefits of the least-cost DP compared with the ‘no transmission’ counterfactual DP, *Accelerated Transition*

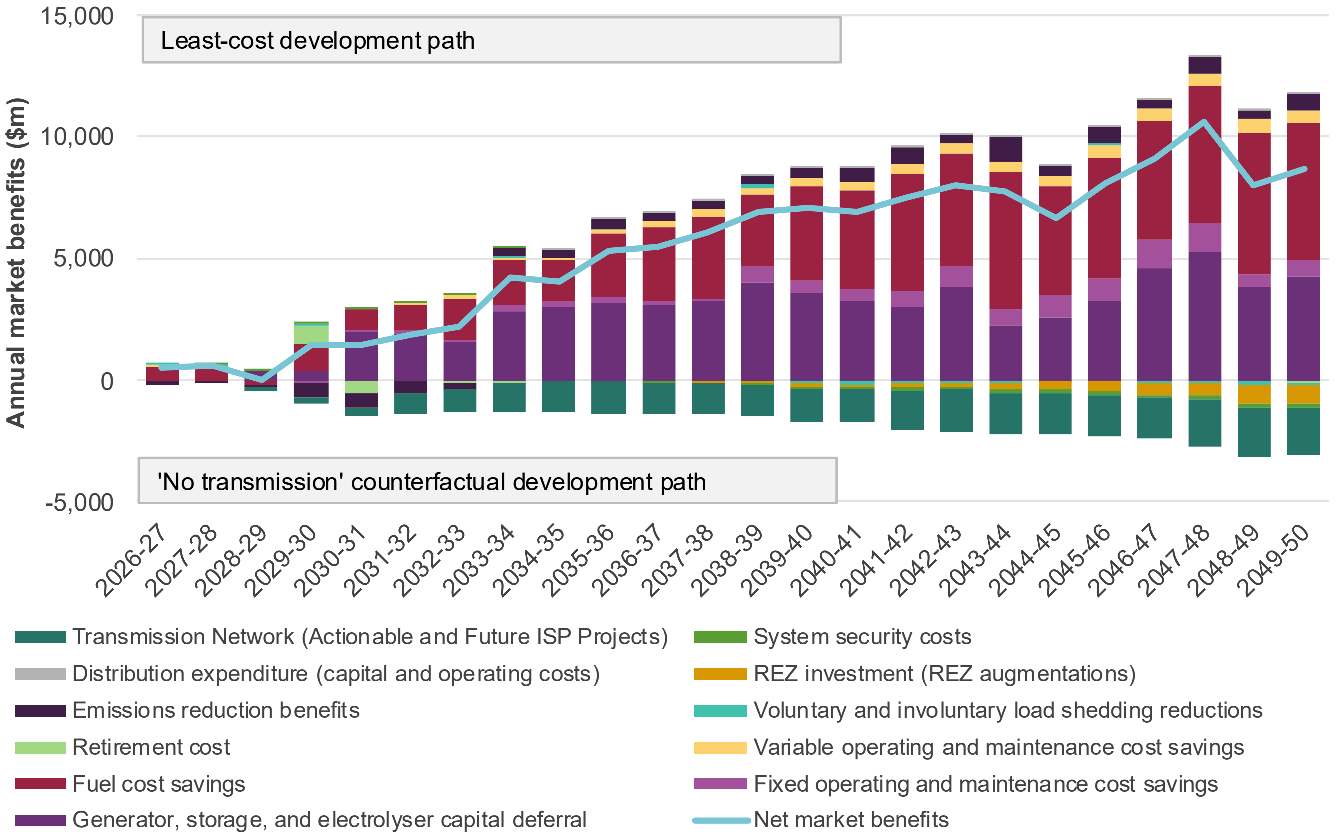
Class of market benefit	Net market benefit (NPV, $ million)
Generator, storage and electrolyser capital deferral	23,099
Fixed operating and maintenance cost savings	3,061
Fuel cost savings	24,892
Variable operating and maintenance cost savings	1,903
Retirement cost	40
Voluntary and involuntary load shedding reductions	-33
Emissions reduction benefits	1,066
REZ investment (REZ augmentations)	-1,193
Distribution expenditure (capital and operating costs)	192
System security costs	-372
Gross market benefits	**52,655**
Transmission Network (Actionable and Future ISP Projects)	-9,947
Total net market benefits	**42,708**

Figure 10 presents the annual net market benefits of the least-cost DP in *Accelerated Transition*. Benefits begin to accrue relatively quickly as transmission assets are developed from 2028-29 in the least cost DP, reducing the need for alternative fuel costs and generator capital investments. Without transmission investment, the cost of operating the NEM with this scenario’s higher emissions reduction targets is also greater given the reduced capability to develop renewable energy in REZs. To compensate for this, the ‘no transmission’ counterfactual DP brings forward coal retirements, particularly in Victoria (and the cost of these closures), as well as additional mid-scale generation builds from 2030-31.

To continue to supply a growing NEM with limited renewable generation options, the ‘no transmission’ counterfactual DP starts to invest in flexible gas with CCS from 2033-34. This increases capital costs and fuel costs in the ‘no transmission’ counterfactual DP. Some additional utility-scale solar and large-scale storages are also required, and broader development of Australia’s offshore wind potential (beyond the Victorian Offshore Wind Target[36]) where the network at point of onshore connection can accommodate the additional capacity (such as in Sydney, Newcastle, and Wollongong) also occurs.

[36] Offshore wind generation in Victoria in the ‘no transmission’ counterfactual DP is subject to significant levels of curtailment due to a lack of existing transmission infrastructure at the points of onshore connection in the Gippsland Offshore and Southern Ocean REZs.

Figure 10 Net market benefits of the least-cost DP relative to the 'no transmission' counterfactual DP in *Accelerated Transition*



With limited development of renewable capacity due to the limited transmission network capacity in the 'no transmission' counterfactual DP, flexible gas with CCS is developed instead to supply electricity consumers. As CCS technologies do not capture all emissions, coal plant retirements are brought forward to ensure sufficient emissions budget is available to operate flexible gas with CCS across the outlook period.

In the 'no transmission' counterfactual DP, the retirement of the Gladstone Power Station would cause significant system reliability risks in Gladstone Grid, as there are insufficient local generation options in the sub-region due to fuel limitations. AEMO does not consider this credible, hence the gas supply limit applied to flexible gas development in Gladstone Grid was assumed to be lifted. CCS technology lead times were also relaxed in Gladstone Grid to enable emissions targets to be met in a reasonable manner.

A6.4.5 Comparing the least-cost development paths across scenarios

Most of the ISP projects considered in the least-cost DPs of each scenario deliver net market benefits in all scenarios. However, their optimal timings differ in ways that are generally proportional to the speed of emissions reduction, coal retirements, and energy consumption growth forecast in each scenario. For example, in *Accelerated Transition,* the pace of transition of the NEM provides increased need for additional projects to be developed at their EISDs to supply higher load growth while meeting stricter emissions reduction requirements.

Table 12 compares the least-cost DPs for each scenario by which projects are actionable and their respective timings.

Table 12 Comparing the least-cost DPs between scenarios

Network option	EISD	Length of Actionable Window (years)	*Slower Growth*	*Step Change*	*Accelerated Transition*
Transmission network development schedule					
Central to North Queensland Reinforcement (Stage 1)	**2029-30**	2		2037-38	2029-30
Central to North Queensland Reinforcement (Stage 2)	**2033-34**	2	2049-50	2042-43	2035-36
Gladstone Project	**2028-29**	4	2028-29	2028-29	2028-29
Central Queensland to Gladstone Grid Expansion - line rebuild option	**2031-32**	2			2035-36
Brisbane Area 275 kV Reinforcement	**2031-32**	2	2037-38	2031-32	2031-32
Auburn River Switching Station[A]	**2031-32**	4			2040-41
Central Queensland to Southern Queensland Expansion[A]	**2031-32**	4			2047-48
Queensland – New South Wales Interconnector (QNI) Connect	**2033-34**	4	2040-41	2041-42	2041-42
Sydney Ring North (Hunter Transmission Project)	**2029-30**	6	2029-30	2029-30	2029-30
Sydney Ring South power flow control option	**2030-31**	4	2030-31	2030-31	2030-31
Sydney Ring South – 500 kV option (Stage 1)	**2033-34**	4	2037-38	2033-34	2033-34
Sydney Ring South – 500 kV option (Stage 2)	**2033-34**	4	2037-38	2033-34	2033-34
Central-West Orana REZ Expansion	**2032-33**	2	2039-40	2032-33	2032-33
Switching Station Near Wondalga	**2030-31**	2	2033-34	2030-31	2030-31
Victoria – New South Wales Interconnector West (VNI West)	**2031-32**	8	2031-32	2031-32	2031-32
Western Victoria Reinforcement program	**2028-29**	2	2039-40	2028-29	2028-29
South West Victoria expansion program	**2033-34**	2		2045-46	
Eastern Victoria Reinforcement Option 1	**2031-32**	2		2033-34	2033-34
Eastern Victoria Reinforcement Option 2	**2031-32**	2	2038-39		
Gippsland Offshore Wind Transmission Stage 1	**2031-32**	2	2033-34	2031-32	2031-32
Gippsland Offshore Wind Transmission Stage 2 – Phase 1	**2033-34**	2	2035-36	2033-34	2033-34
Gippsland Offshore Wind Transmission Stage 2 – Phase 2	**2038-39**	2	2038-39	2038-39	2038-39
Project Marinus Stage 2	**2034-35**	8	2034-35	2046-47	2034-35
North West Tasmania REZ option	**2030-31**	2	2032-33	2030-31	2030-31
Central Highlands REZ option	**2030-31**	4			2030-31
Heywood Interconnector Upgrade	**2031-32**	2			2042-43
SESA-CSA Transmission Upgrade	**2029-30**	2			2042-43
Northern Transmission Project	**2029-30**	4			2041-42
Distribution network development opportunities					
Hunter-Central Coast REZ Expansion	**2030-31**	Not applicable			2030-31
Dubbo Distribution Project (Option 1)	**2030-31**	Not applicable		2032-33	2030-31
Dubbo Distribution Project (Option 2a)	**2031-32**	Not applicable		2033-34	2031-32

A. Part of the Central Queensland to Southern Queensland Expansion project.
Note: Light teal indicates that a project is delivered within its actionable window.

As further detailed in Appendix A5 Network Investments, approximately 6,000 km of transmission is projected to be needed in total by 2050 in *Step Change*. About half this work is already well underway in committed and anticipated projects.

Slower Growth follows a lower trajectory with less need for transmission projects given the lower levels of load growth assumed in this scenario. The pace of demand growth and the greater need to reduce emissions in *Accelerated Transition* results in earlier builds compared with the other scenarios and some additional builds in South Australia and Queensland.

A6.5 Step 2: Building candidate development paths

A6.5.1 Identifying potential actionable and future ISP projects

Projects in each least-cost DP form the basis of the CDPs to be assessed in the next stage of the CBA. **Table 13** presents the projects identified as being potentially actionable in at least one scenario or identified as actionable in the 2024 ISP. The table provides details of the duration of their 'actionable windows' – a concept described in the *ISP Methodology* and used to assess whether a project that is currently actionable from the 2024 ISP should retain its actionable status in this ISP.

For those projects, the actionable window may be longer than two years (the time between ISPs), because the project has been advancing for at least two years already, and if it does not maintain its actionability, the EISD would slip by a period commensurate with the length of time it has been under development because regulatory approvals, early works, or preparatory activities may need to be repeated or renewed if it is stopped and then subsequently actioned in future[37]. The duration of the actionable window is two years from the EISD for a newly actionable project, while the duration for an existing actionable project is extended by a further two years for each ISP it was previously identified as actionable. In all tables in this document, the actionable window is always inclusive of the EISD. See Appendix A5 for more information on network investments.

[37] This does not consider the potentially detrimental impact on social licence, community trust and acceptance.

Table 13 Options that could meet the needs of potential actionable projects in the 2026 ISP or projects identified as actionable in the 2024 ISP

Network option considered	Scenario(s) that the project is identified as potentially actionable	EISD or first year of actionable window	Length of actionable window (years)	Last year of actionable window
Transmission network development schedule				
Central to North Queensland Reinforcement (Stage 1)	*Accelerated Transition*	2029-30	2	2031-32
Gladstone Project	All scenarios	2028-29	4	2032-33
Central Queensland to Southern Queensland Expansion	Found actionable in 2024 ISP but potentially not in the 2026 ISP	2031-32	4	2035-36
Brisbane Area 275 kV Reinforcement	*Step Change* and *Accelerated Transition*	2031-32	2	2033-34
Queensland – New South Wales Interconnector (QNI) Connect	Found actionable in 2024 ISP but potentially not in the 2026 ISP	2033-34	4	2037-38
Sydney Ring North (Hunter Transmission Project)	All scenarios	2029-30	6	2035-36
Sydney Ring South power flow control option	All scenarios	2030-31	4	2034-35
Sydney Ring South – 500 kV option (Stage 1)	*Step Change* and *Accelerated Transition*	2033-34	4	2037-38
Sydney Ring South – 500 kV option (Stage 2)	*Step Change* and *Accelerated Transition*	2033-34	4	2037-38
Central-West Orana REZ Expansion	*Step Change* and *Accelerated Transition*	2032-33	2	2034-35
Switching Station Near Wondalga	*Slower Growth* and *Accelerated Transition*	2030-31	2	2032-33
Victoria – New South Wales Interconnector West (VNI West)	All scenarios	2031-32	8	2039-40
Western Victoria Reinforcement program	*Step Change* and *Accelerated Transition*	2028-29	2	2030-31
Gippsland Offshore Wind Transmission Stage 1	*Step Change* and *Accelerated Transition*	2031-32	2	2033-34
Gippsland Offshore Wind Transmission Stage 2 – Phase 1	*Step Change* and *Accelerated Transition*	2033-34	2	2035-36
Gippsland Offshore Wind Transmission Stage 2 – Phase 2	all scenarios	2038-39	2	2040-41
Project Marinus Stage 2	*Slower Growth* and *Accelerated Transition*	2034-35	8	2042-43
North West Tasmania REZ option	All scenarios	2030-31	2	2032-33
Central Highlands REZ option	*Accelerated Transition*	2030-31	4	2034-35
Northern Transmission Project	Found actionable in 2024 ISP but potentially not in the 2026 ISP	2029-30	4	2033-34
Distribution network development opportunities				
Hunter-Central Coast REZ Expansion[B]	Optimal to deliver in *Accelerated Transition*	2030-31	2	2032-33
Dubbo Distribution Project (Option 1)[B]	Optimal to deliver in *Accelerated Transition*	2030-31	2	2032-33
Dubbo Distribution Project (Option 2a)[B]	Optimal to deliver in *Accelerated Transition*	2031-32	2	2033-34

A. HumeLink, Hunter-Central Coast REZ Network Infrastructure project, Project Marinus Stage 1, and New England REZ Network Infrastructure Project are sufficiently progressed to be assessed as anticipated, hence, these projects are developed at the proponent's timing in all DPs assessed in this ISP.
B. While Hunter-Central Coast REZ Expansion and Dubbo Distribution Project (Option 1 and Option 2a) are shown alongside transmission options, the ISP framework cannot directly action distribution augmentations. The projects may progress through the regulatory investment test for distribution (RIT-D) or the New South Wales *Electricity Infrastructure Investment Act 2020*.

A6.5.2 Determining the set of candidate development paths to identify the ODP

A CDP represents a collection of DPs that have the same potential actionable projects. CDPs vary with respect to these potential actionable projects and represent adaptable paths for investments in future projects (enabling future projects to be developed at a timing most appropriate for each scenario's needs, including potentially not developing the project across the ISP outlook period).

The least-cost DPs from all scenarios are used as the basis for forming the initial set of CDPs. Additional CDPs are added based on the process set out in the *ISP Methodology* which involves forming new CDPs by changing the timing of potential actionable projects in an existing CDP or by including additional or alternate actionable projects to a CDP.

The CDPs examined in this 2026 ISP are shown in **Table 14**, which also sets out how each CDP is developed. CDPs have been designed to primarily explore the set of projects that were identified as forming the least-cost development path in *Step Change* as well as a subset of projects identified as potentially actionable in *Accelerated Transition* or *Slower Growth*. The resulting estimates of total system cost relating to each CDP can then be compared with each other to test the impact of a project on the total system cost, as is done in Section A6.7.

Note that the costs and benefits of CDPs, as well as the CDP collection itself, for this 2026 ISP are not directly comparable to the CDPs used in the 2024 ISP nor to the 2026 Draft ISP as there have been a series of significant changes to the inputs and assumptions used to calculate the total system cost. This is further explained in Section A6.2.

The first three CDPs were based on the least-cost DPs from each scenario:

- **CDP 1** which is based on the least-cost DP in *Slower Growth* as defined in **Table 12**,
- **CDP 2** which is based on the least-cost DP in *Step Change* as defined in **Table 12**, and
- **CDP 3** which is based on the least-cost DP in *Accelerated Transition* as defined in **Table 12**.

CDP 2 forms the basis of **CDP 4**, but **CDP 4** includes an actionable Project Marinus Stage 2 as it was found to be optimal at its EISD in both CDP 1 and CDP 3, and an actionable Central to North Queensland Reinforcement (Stage 1) and delivery of Hunter-Central Coast REZ Expansion at its EISD, which were both found to produce benefits in *Accelerated Transition* compared to their costs.

The following CDPs, which are variations of CDP 4, assessed the benefits of potential actionable projects by providing alternative CDPs that provide a comparison with key projects being delayed to future projects or not at all (not actionable), or delivered at their EISD (actionable):

- **CDP 5** features delivery of Central to North Queensland Reinforcement (Stage 1) outside its actionable window in contrast with CDP 4.
- **CDP 6** features delivery of Gladstone Project outside its actionable window in contrast with CDP 4.
- **CDP 7** features delivery of Brisbane Area 275 kV Reinforcement outside its actionable window in contrast with CDP 4.
- **CDP 8** features delivery of Central Queensland to Southern Queensland Expansion within its actionable window in contrast with CDP 4, given it was found to be an actionable project in the 2024 ISP.
- **CDP 9** features delivery of QNI Connect within its actionable window in contrast with CDP 4, given it was found to be an actionable project in the 2024 ISP and Draft 2026 ISP.

- **CDP 10** features delivery of only Sydney Ring South power flow control option outside its actionable window, in contrast with CDP 4. Note that the benefits of Sydney Ring South power flow control option could also be delivered by Sydney Ring South – 500 kV option (Stage 1 and Stage 2) project, and that its non-actionable delivery (post-July 2034) is after the EISD (July 2033) of Sydney Ring South – 500 kV option (Stage 1 and Stage 2). As such, in this CDP, delivering the Sydney Ring South power flow control option outside its actionable window is best represented by not delivering it at all.
- **CDP 11** features delivery of both Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option outside their actionable windows in contrast with CDP 4. Note this CDP also delays Sydney Ring South – 500 kV option (Stage 1 and Stage 2) to be delivered along with Sydney Ring North (Hunter Transmission Project) (but still within its actionable window) and assumes that the Sydney Ring South power flow control option is not delivered at all, per CDP 10.
- **CDP 12** features delivery of Sydney Ring South – 500 kV option (Stage 1 and Stage 2) outside its actionable window in contrast with CDP 4.
- **CDP 13** extends CDP 11 to delay the delivery of Sydney Ring South – 500 kV option (Stage 1 and Stage 2) to outside of its actionable window. In this CDP, Sydney Ring South power flow control option is assumed to be delivered alongside Sydney Ring North (Hunter Transmission Project), but before Sydney Ring South – 500 kV option (Stage 1 and Stage 2).
- **CDP 14** features delivery of Central-West Orana REZ Expansion outside its actionable window in contrast with CDP 4.
- **CDP 15** features delivery of Switching Station near Wondalga outside its actionable window in contrast with CDP 4.
- **CDP 16** features delivery of VNI West outside of its actionable window in contrast with CDP 4.
- **CDP 17** features delivery of Western Victoria Reinforcement program outside its actionable window in contrast with CDP 4.
- **CDP 18** features delivery of the smaller Eastern Victoria Reinforcement Option 1 within its actionable window in contrast with CDP 4, given the augmentation of this flow path was assessed in the Draft 2026 ISP.
- **CDP 19** features delivery of the larger Eastern Victoria Reinforcement Option 2 to within its actionable window instead of the smaller option (Option 1) in contrast with CDP 18 to ensure robustness of the assessment for this flow path.
- **CDP 20** features delivery of Gippsland Offshore Wind Transmission Stage 1 outside its actionable window in contrast with CDP 4.
- **CDP 21** features delivery of Gippsland Offshore Wind Transmission Stage 2 – Phase 1 outside its actionable window in contrast with CDP 4.
- **CDP 22** features delivery of Gippsland Offshore Wind Transmission Stage 2 – Phase 2 outside its actionable window in contrast with CDP 4.
- **CDP 23** combines CDP 20 - CDP 22 to delay the delivery of both stages of the Gippsland Offshore Wind Transmission project to outside their actionable windows.
- **CDP 24** features delivery of Project Marinus Stage 2 outside its actionable window in contrast with CDP 4.
- **CDP 25** features delivery of North West Tasmania REZ option outside its actionable window in contrast with CDP 4**.**

- **CDP 26** combines CDP 24 and CDP 25 to delay the delivery of both North West Tasmania REZ option and Project Marinus Stage 2 to outside their actionable windows.
- **CDP 27** features delivery of Central Highlands REZ option with its actionable window in contrast with CDP 4. It was found to be an actionable project in the 2024 ISP and Draft 2026 ISP, and the project's delivery is also found optimal within its actionable window in CDP 3.
- **CDP 28** features delivery of the Northern Transmission Project (formerly Mid North South Australia REZ Expansion project) at a timing within its actionable window, given it was found to be an actionable project in the 2024 ISP.

To demonstrate a robust and comprehensive approach to identifying the ODP, the following CDPs assessed delaying the delivery of multiple projects across the NEM to non-actionable timings:

- **CDP 29** features delivery of Switching Station Near Wondalga and Sydney Ring South – 500 kV option (Stage 1 and Stage 2) outside their actionable windows, in contrast with CDP 4.
- **CDP 30** features delivery of VNI West and Central West Orana REZ Expansion outside their actionable windows, in contrast with CDP 4.
- **CDP 31** features delivery of VNI West and Sydney Ring South – 500 kV option (Stage 1 and Stage 2) outside their actionable windows, in contrast with CDP 4.
- **CDP 32** features delivery of VNI West, Switching Station Near Wondalga and Sydney Ring South – 500 kV option (Stage 1 and Stage 2) outside of their actionable windows, in contrast with CDP 4.
- **CDP 33** features delivery of VNI West and Switching Station Near Wondalga outside their actionable windows, in contrast with CDP 4.
- **CDP 34** features delivery of all actionable projects in CDP 4 to a timing outside their actionable window.

Table 14 Candidate development paths summary

In this CDP...		...these projects would be actionable																							
CDP	**Description**	**Central to North Queensland Reinforcement (Stage 1)**	**Gladstone Project**	**Brisbane Area 275 kV Reinforcement**	**Central Queensland to Southern Queensland Expansion**	**QNI Connect**	**Sydney Ring South power flow control option**	**Sydney Ring North (Hunter Transmission Project)**	**Sydney Ring South – 500 kV option (Stage 1 and Stage 2)**	**Central-West Orana REZ Expansion**	**Switching Station near Wondalga**	**VNI West**	**Western Victoria Reinforcement program**	**Eastern Victoria Reinforcement Option 1**	**Eastern Victoria Reinforcement Option 2**	**Gippsland Offshore Wind Transmission Stage 1**	**Gippsland Offshore Wind Transmission Stage 2 – Phase 1**	**Gippsland Offshore Wind Transmission Stage 2 – Phase 2**	**Northern Transmission Project**	**Project Marinus Stage 2**	**North West Tasmania REZ option**	**Central Highlands REZ option**	**Hunter-Central Coast REZ Expansion[C]**	**Dubbo Distribution Project (Option 1)[C]**	**Dubbo Distribution Project (Option 2a)[C]**
CDP 1	Least-cost DP for *Slower Growth*		✓				✓	✓				✓						✓		✓					
CDP 2	Least-cost DP for *Step Change*		✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓			✓				
CDP 3	Least-cost DP for *Accelerated Transition*	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	✓	✓	✓	✓
CDP 4	CDP 2 with actionable Project Marinus Stage 2, Central to North Queensland Reinforcement (Stage 1), and Hunter-Central Coast REZ Expansion at EISD	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	×	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 6	CDP 4 without actionable Gladstone Project	✓	×	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	✓	✓	×			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 8	CDP 4 with actionable Central Queensland to Southern Queensland Expansion	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 9	CDP 4 with actionable Queensland – New South Wales Interconnector (QNI) Connect	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	✓	✓	✓			×	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 11	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option	✓	✓	✓			×	×	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		

In this CDP…		…these projects would be actionable																							
CDP	Description	Central to North Queensland Reinforcement (Stage 1)	Gladstone Project	Brisbane Area 275 kV Reinforcement	Central Queensland to Southern Queensland Expansion	QNI Connect	Sydney Ring South power flow control option	Sydney Ring North (Hunter Transmission Project)	Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	Central-West Orana REZ Expansion	Switching Station near Wondalga	VNI West	Western Victoria Reinforcement program	Eastern Victoria Reinforcement Option 1	Eastern Victoria Reinforcement Option 2	Gippsland Offshore Wind Transmission Stage 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 2	Northern Transmission Project	Project Marinus Stage 2	North West Tasmania REZ option	Central Highlands REZ option	Hunter-Central Coast REZ Expansion[c]	Dubbo Distribution Project (Option 1)[c]	Dubbo Distribution Project (Option 2a)[c]
CDP 12	CDP 4 without actionable Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	✓	✓	✓			✓	✓	×	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	✓	✓	✓			×	×	×	✓	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 14	CDP 4 without actionable Central-West Orana REZ Expansion	✓	✓	✓			✓	✓	✓	×	✓	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	✓	✓	✓			✓	✓	✓	✓	×	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 16	CDP 4 without actionable VNI West	✓	✓	✓			✓	✓	✓	✓	✓	×	✓			✓	✓	✓		✓	✓		✓		
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	✓	✓	✓			✓	✓	✓	✓	✓	✓	×			✓	✓	✓		✓	✓		✓		
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓		✓		
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓		✓	✓		✓		
CDP 20	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 1	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			×	✓	✓		✓	✓		✓		
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	×	✓		✓	✓		✓		
CDP 22	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	×		✓	✓		✓		
CDP 23	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 1, Stage 2 – Phase 1 and Stage 2 – Phase 2	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			×	×	×		✓	✓		✓		
CDP 24	CDP 4 without actionable Project Marinus Stage 2	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		×	✓		✓		

CDP	Description	Central to North Queensland Reinforcement (Stage 1)	Gladstone Project	Brisbane Area 275 kV Reinforcement	Central Queensland to Southern Queensland Expansion	QNI Connect	Sydney Ring South power flow control option	Sydney Ring North (Hunter Transmission Project)	Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	Central-West Orana REZ Expansion	Switching Station near Wondalga	VNI West	Western Victoria Reinforcement program	Eastern Victoria Reinforcement Option 1	Eastern Victoria Reinforcement Option 2	Gippsland Offshore Wind Transmission Stage 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 2	Northern Transmission Project	Project Marinus Stage 2	North West Tasmania REZ option	Central Highlands REZ option	Hunter-Central Coast REZ Expansion[C]	Dubbo Distribution Project (Option 1)[C]	Dubbo Distribution Project (Option 2a)[C]
In this CDP…		**…these projects would be actionable**																							
CDP 25	CDP 4 without actionable North West Tasmania REZ option	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	×		✓		
CDP 26	CDP 4 without actionable North West Tasmania REZ option and actionable Project Marinus Stage 2	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		×	×		✓		
CDP 27	CDP 4 with actionable Central Highlands REZ option	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	✓	✓		
CDP 28	CDP 4 with actionable Northern Transmission Project	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	✓		✓		
CDP 29	CDP 4 without actionable Switching Station Near Wondalga and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	✓	✓	✓			✓	✓	×	✓	×	✓	✓			✓	✓	✓		✓	✓		✓		
CDP 30	CDP 4 without actionable VNI West and Central-West Orana REZ Expansion	✓	✓	✓			✓	✓	✓	×	✓	×	✓			✓	✓	✓		✓	✓		✓		
CDP 31	CDP 4 without actionable VNI West and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	✓	✓	✓			✓	✓	×	✓	✓	×	✓			✓	✓	✓		✓	✓		✓		
CDP 32	CDP 4 without actionable VNI West, Switching Station Near Wondalga and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	✓	✓	✓			✓	✓	×	✓	×	×	✓			✓	✓	✓		✓	✓		✓		
CDP 33	CDP 4 without actionable VNI West and Switching Station Near Wondalga	✓	✓	✓			✓	✓	✓	✓	×	×	✓			✓	✓	✓		✓	✓		✓		
CDP 34	CDP 4 without actionable projects	×	×	×			×	×	×	×	×	×	×			×	×	×		×	×		×		

A: ✓ refers to a project added as actionable to CDP 4, × refers to a project being removed as actionable from CDP 4.

B: Teal rows represent least cost DPs. Purple rows represent CDP 4 and the CDPs developed from it.

C: The ISP framework does not apply to Hunter-Central Coast REZ Expansion and Dubbo Distribution Project (Option 1 and Option 2a), highlighted in gold. The projects may progress through the regulatory investment test for distribution (RIT-D) or the New South Wales *Electricity Infrastructure Investment (EII) Act*.

A6.6 Steps 3 and 4: Assessing the candidate development paths

A6.6.1 Ranking the candidate development paths

The identification of the ODP is informed by assessing the performance of the CDPs across all the scenarios as well as their resilience across the sensitivities implemented (see Section A6.9). This section compares the various CDPs to explore the costs and benefits provided by potential actionable projects.

The *ISP Methodology* outlined two approaches that are used to rank the CDPs, which are:

- **Approach A (risk neutral)** – **a scenario-weighted approach** to averaging the net market benefits of each CDP across all scenarios. CDPs are ranked in descending order according to their weighted net market benefits, and
- **Approach B (risk averse)** – **a least-worst-weighted regrets (LWWR) approach** which calculates the 'regrets' of CDPs in each scenario, weights those regrets by the relative scenario likelihood, and determines the maximum 'weighted regrets' across the scenarios. CDPs are ranked in ascending order based on maximum weighted regrets. 'Regrets' represent the difference between the net market benefits of a CDP in a scenario and the net market benefits of the least-cost DP in that scenario, effectively being the 'regret' of having developed investments that were not as beneficial (either due to be in excess of, or short of, future needs) if the future conditions had been known with certainty at the time of making the investment decision(s).

Table 15 shows the net market benefits of each CDP in each scenario, the weighted net market benefits, the worst weighted regrets, and the rankings under each approach.

Table 15 Performance of candidate development paths across scenarios (in $ billion) – ranked in order of weighted net market benefits

		Scenario-specific net market benefits			Approach A		Approach B	
CDP	**Description**	***Slower Growth***	***Step Change***	***Accelerated Transition***	**Weighted net market benefits (WNMB)**	**Rank based on WNMB**	**Worst weighted regrets (WWR)**	**Rank based on WWR**
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	10.29	29.55	42.55	27.86	1	0.14	5
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	10.30	29.58	42.47	27.85	2	0.14	3
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	10.29	29.54	42.53	27.85	3	0.14	6
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	10.30	29.52	42.50	27.84	4	0.14	1
CDP 14	CDP 4 without actionable Central-West Orana REZ Expansion	10.43	29.43	42.52	27.83	5	0.16	9
CDP 27	CDP 4 with actionable Central Highlands REZ option	10.25	29.50	42.56	27.83	6	0.15	7
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	10.20	29.54	42.55	27.83	7	0.16	10
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	10.30	29.50	42.51	27.83	8	0.14	2
CDP 25	CDP 4 without actionable North West Tasmania REZ option	10.29	29.50	42.50	27.82	9	0.14	4
CDP 3	Least-cost DP for *Accelerated Transition*	9.97	29.49	42.71	27.79	10	0.23	14
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	10.24	29.47	42.43	27.78	11	0.15	8
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	10.45	29.35	42.40	27.77	12	0.19	12
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	10.18	29.48	42.12	27.68	13	0.17	11
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	10.37	29.33	42.15	27.67	14	0.20	13
CDP 2	Least-cost DP for *Step Change*	9.52	29.77	42.26	27.67	15	0.35	23
CDP 29	CDP 4 without actionable Switching Station Near Wondalga and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	10.40	29.06	42.45	27.63	16	0.33	21
CDP 12	CDP 4 without actionable Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	10.38	29.08	42.43	27.63	17	0.32	20

		Scenario-specific net market benefits			Approach A		Approach B	
CDP 22	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	10.17	29.27	42.26	27.62	18	0.23	15
CDP 24	CDP 4 without actionable Project Marinus Stage 2	9.28	29.66	42.49	27.62	19	0.41	26
CDP 26	CDP 4 without actionable North West Tasmania REZ option and actionable Project Marinus Stage 2	9.29	29.64	42.46	27.60	20	0.41	25
CDP 30	CDP 4 without actionable VNI West and Central-West Orana REZ Expansion	10.42	29.29	41.60	27.52	21	0.30	18
CDP 16	CDP 4 without actionable VNI West	10.28	29.31	41.64	27.50	22	0.29	16
CDP 33	CDP 4 without actionable VNI West and Switching Station Near Wondalga	10.30	29.29	41.60	27.49	23	0.30	17
CDP 32	CDP 4 without actionable VNI West, Switching Station Near Wondalga, and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	10.45	29.09	41.71	27.47	24	0.31	19
CDP 31	CDP 4 without actionable VNI West and Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	10.43	29.02	41.75	27.44	25	0.34	22
CDP 28	CDP 4 with actionable Northern Transmission Project	9.69	28.99	42.25	27.36	26	0.36	24
CDP 20	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 1	10.37	28.55	41.54	27.14	27	0.56	27
CDP 23	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 1, Gippsland Offshore Wind Transmission Stage 2 – Phase 1, and Gippsland Offshore Wind Transmission Stage 2 – Phase 2	10.27	28.37	41.35	26.98	28	0.64	28
CDP 1	Least-cost DP for *Slower Growth*	10.80	28.07	40.80	26.84	29	0.78	31
CDP 8	CDP 4 with actionable Auburn River Switching Station and Central Queensland to Southern Queensland Expansion	8.88	28.18	41.56	26.58	30	0.73	29
CDP 6	CDP 4 without actionable Gladstone Project	9.66	28.15	39.92	26.34	31	0.75	30
CDP 11	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option	8.65	24.65	39.94	24.46	32	2.35	32
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	8.59	24.58	39.89	24.40	33	2.39	33
CDP 34	CDP 4 without actionable projects	7.42	23.05	34.00	21.78	34	3.09	34

The table above shows that most CDPs deliver more than $29 billion in net market benefits in the most likely *Step Change* scenario. Weighted across the three scenarios, the benefits remain above $27 billion.

The results also show that there are significant benefits in commencing, or continuing, with the potential actionable transmission developments. In contrast, delaying all projects to outside of their actionable window (CDP 34) is a key outlier, delivering over $6 billion fewer benefits than the top CDP, and having over $3 billion more regret (had the investments been made with certainty of which scenario would eventuate). While still more beneficial than the 'no transmission' counterfactual DP, slowing down the development of the key transmission projects to outside their actionable windows is less beneficial than continuing to develop the NEM's transmission system in a timely manner.

A number of CDPs (CDP 29 to CDP 33) test combinations of projects at non-actionable timings. These have been designed to ensure coverage of the potential for less projects to be found actionable collectively. On a weighted net market benefits basis, these CDPs are significantly worse than the majority of CDPs, and perform similarly, or marginally better than, the least-cost DP for *Slower Growth*, as these projects deliver significant benefits in the other two scenarios.

A6.6.2 Newly committed and anticipated projects since the 2024 ISP

Since the 2024 ISP, four projects have sufficiently progressed to be classified as committed or anticipated, and as such AEMO has considered these transmission projects as being delivered at the time advised by the proponent in all scenarios. The projects are not re-evaluated in the ISP's cost-benefit analysis.

HumeLink

The transmission network between Southern New South Wales (SNSW) and Central New South Wales (CNSW) sub-regions provides access for the hydro-electric generation in the Snowy mountains, renewable generation in SNSW, and import from Victoria and South Australia to New South Wales major load centres, and is expected to be completed by December 2027.

Hunter-Central Coast REZ Network Infrastructure project

Hunter-Central Coast REZ Network Infrastructure project was identified as an actionable New South Wales project in the 2024 ISP. As per the June 2026 publication of the Transmission Augmentation Information page[38], it is now sufficiently progressed to be considered a committed project, therefore it was included across all scenarios and CDPs, and it has not been further assessed in this ISP.

Project Marinus Stage 1

Project Marinus is a proposed 1,500 MW capacity undersea and underground electricity interconnection between Tasmania and Victoria delivered by Marinus Link Pty Ltd, which will be operating in parallel with the existing Basslink interconnector. It is proposed to be delivered as two 750 MW high voltage direct current (HVDC) developments between Burnie area in Tasmania and Latrobe Valley in Victoria.

Project Marinus was identified as an actionable ISP project in the 2022 ISP and confirmed as an actionable ISP project in the 2024 ISP. Marinus Link Pty Ltd and TasNetworks have completed a RIT-T for this network augmentation. The Project

[38] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Assessment Conclusions Report (PACR), the third report of the RIT-T, was published in June 2021. This RIT-T analysis was updated in July 2025. Project Marinus passed AEMO's feedback loop assessment in August 2025[39].

Project Marinus Stage 1 has reached financial close and is now considered an anticipated project. Therefore, it was included across all scenarios and CDPs and has not been further assessed in this ISP. However, the second stage of this project has not achieved anticipated status, hence it was still assessed in this ISP.

New England REZ Network Infrastructure Project

On 17 December 2021, the New England REZ was formally declared to progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than through the RIT-T framework. This declaration identifies that the New South Wales Energy Corporation (EnergyCo) is the appointed infrastructure planner responsible for coordinating the development of the REZ.

The new transmission network for the REZ, the New England REZ Network Infrastructure Project, comprises a flow path augmentation providing a 6,000 MW increase in transfer capacity in both directions to Central New South Wales and to Northern New South Wales. It also provides an equivalent 6,000 MW transfer capacity increase with the New England REZ. The major augmentation was first identified as an actionable New South Wales project in the 2022 ISP and again in the 2024 ISP. Following advice from the New South Wales Government[40], AEMO now considers the project as sufficiently progressing to be classified as anticipated for the 2026 ISP, with an expected delivery date of January 2034.

More information about the delivery of the New England REZ is available on EnergyCo New South Wales website[41].

A6.6.3 Assessing the actionability of key projects in the CDPs

This section explores the value of individual projects being delivered within each project's actionable window. The discussion below focuses on key projects that are developed at their EISD or proponent's timing in the least-cost DPs for the scenarios assessed.

Two slightly different assessments were considered – one, where a specific project is removed entirely from the path, and the other where the project's actionability is tested:

- **Removing entirely** – for each of the projects discussed below, the relative market benefits of that project are first evaluated by comparing the CDP that provides the highest weighted net market benefits with another CDP that features the equivalent set of actionable and future projects, at a given set of timings, except the project of interest. This comparison, referred to as the 'TOOT' (Take-one-out-at-a-time) approach, is provided on *Step Change* and on other scenarios where appropriate. For the purposes of this 2026 ISP, this has been assessed using CDP 4 (the CDP around which most other CDPs have been based upon).
- **Assessing actionability** – once the relative market benefits of a potential actionable project are assessed, the merits of progressing the project at an actionable timing or delaying the project to after its actionable window (and then waiting for the next ISP to determine whether to proceed) are then considered. This is completed by comparing the weighted net market benefits and weighted regrets of a CDP where the delivery of the project of interest is delayed until after

[39] At https://www.aemo.com.au/newsroom/news-updates/project-marinus-passes-feedback-loop-assessment.

[40] Letter from the Honourable Penny Sharpe MLC regarding the New England REZ Network Infrastructure Project, 12 May 2026, at https://www.aemo.com.au/-/media/files/major-publications/isp/2026/supporting-materials/2026-isp-ministerial-letter-new-england-rez.pdf.

[41] See https://www.energyco.nsw.gov.au/ne-rez.

the actionable window for that scenario against a CDP that delivers the project within its actionable window – at the proponent's timing or EISD, as appropriate. Unless otherwise stated, most of the CDP actionability comparisons in the following subsections are against CDP 4 with relative market benefits rounded to the nearest ten million.

Caution must be taken when adding up the individual relative market benefits of each project as laid out in the sections below and comparing it against the ODP's weighted net market benefits. Since there could be synergies across multiple projects, the relative market benefits of a project are dependent on delivery of other projects, and therefore the sum of each project's identified relative benefit may not add to the total benefits of the aggregate ODP. Nevertheless, the TOOT approach is a useful (if imperfect) approach to estimate individual project value.

Central to North Queensland Reinforcement (Stage 1)

	CQ- NQ Option 3
EISD	December 2029[42]
Actionable window length	Two years (Actionable in *Accelerated Transition*)
Reported cost[43]	$209 million Class 5b (±50%)
Cost adjusted for transmission cost escalation	$217 million (*Slower Growth*, 2029-30) $218 million (*Step Change*, 2029-30) $222 million (*Accelerated Transition*, 2029-30)
Flow path or REZ	Central Queensland to Northern Queensland
Capacity increase	350 MW forward/500 MW reverse

The Central to North Queensland Reinforcement (Stage 1) involves stringing a second 275 kV circuit between Stanwell and Broadsound on the existing line. The aim of this project is to increase the capability of the transmission network between Central Queensland and Northern Queensland and enable access to lower-cost generation from Northern Queensland to meet demand in the Queensland major load centres. It increases flow capacity from Central Queensland to Northern Queensland by up to 350 MW in the northern direction and 500 MW in the southern direction. This project also alleviates a limitation on combined flows from Northern Queensland and the Isaac REZ by an additional 600 MW. This project has not been identified as actionable in any previous ISP and thus has an actionable window of two years.

In the least-cost DP for *Accelerated Transition*, the Central to North Queensland Reinforcement (Stage 1) project is found optimal at its EISD of December 2029. This enables the transfer of more existing wind generation from Northern to Central Queensland and Southern Queensland and decreases the utilisation of flexible gas in the region in the early 2030s. The optimal timing of the project is in 2037-38 in the *Step Change* least-cost DP, while not needed within the outlook period in *Slower Growth*.

Assessing the relative market benefits of Central to North Queensland Reinforcement (Stage 1) via TOOT analysis

Table 16 and **Figure 11** present the relative market benefits of delivering Central to North Queensland Reinforcement (Stage 1) at its EISDs (2029-30) in *Step Change* over not at all. The project has a positive relative market benefit of around

[42] AEMO modelled this project with an EISD of December 2029, as advised by Powerlink for the 2025 *Electricity Network Options Report*, but Powerlink has subsequently advised a later timing.

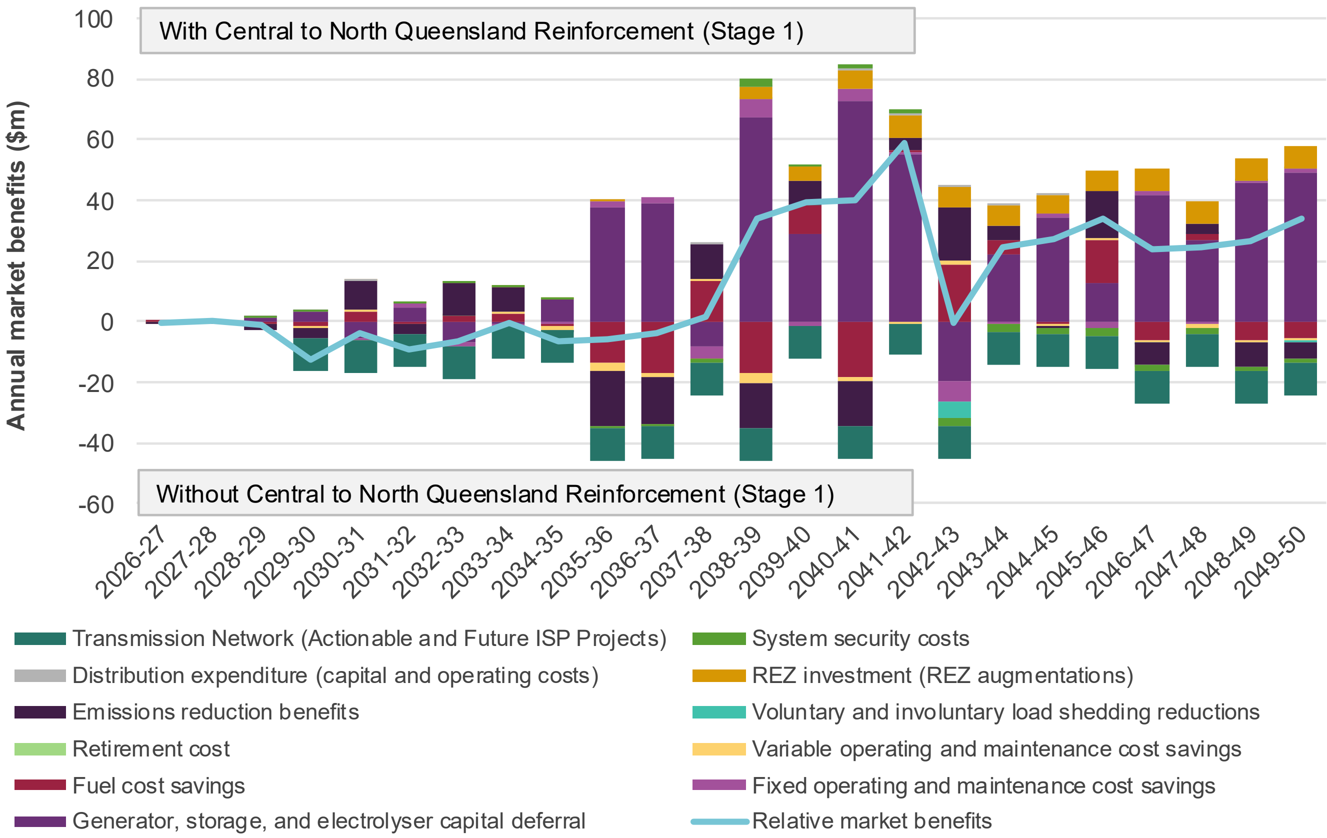
[43] 'Reported cost' refers to the estimate prepared by AEMO and reviewed by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

$75 million, as the additional transmission network cost is fully offset by generation and storage capital deferral, REZ investment savings, and operating cost savings. The augmentation enables development of more wind generation in Northern Queensland and reduces the need for more costly investment in greater capacities of utility-scale solar in Central and Southern Queensland. This project also impacts the build in Northern New South Wales and Central New South Wales, increasing further development of utility-scale solar in these two sub-regions allowing for greater renewable energy available to flow into New South Wales and less development of wind from the late 2030s.

Table 16 Relative market benefits of Central to North Queensland Reinforcement (Stage 1) in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	158
Fixed operating and maintenance cost savings	0
Fuel cost savings	-8
Variable operating and maintenance cost savings	-4
Retirement cost	0
Voluntary and involuntary load shedding reductions	-2
Emissions reduction benefits	-0
REZ investment (REZ augmentations)	21
Distribution expenditure (capital and operating costs)	0
System security costs	-3
Gross market benefits	**163**
Transmission Network (Actionable and Future ISP Projects)	-88
Total relative market benefits	**75**

Figure 11 Annual relative market benefits of Central to North Queensland Reinforcement (Stage 1) in *Step Change* (2029-30)



Assessing the net market benefits of Central to North Queensland Reinforcement (Stage 1) as an actionable project

The benefits associated with delivering Central to North Queensland Reinforcement (Stage 1) at an actionable timing are demonstrated through a comparison between CDP 4, in which the project's delivery is at its EISD, and CDP 5, in which the project's delivery is outside its actionable window. **Table 17** shows that Central to North Queensland Reinforcement (Stage 1) would deliver similar weighted net market benefits when actionable, even though this was not the optimal timing in *Step Change*, the most likely scenario. While the WNMB of CDP 4 and CDP 5 are very similar, by delivering the project at an actionable timing, greater reliability risk mitigation is provided to cover the possibility that *Accelerated Transition* may eventuate, particularly as alternative options would be more costly if required.

Table 17 Comparing net market benefits between CDP 4 and CDP 5 ($ billion) – Central to North Queensland Reinforcement (Stage 1)

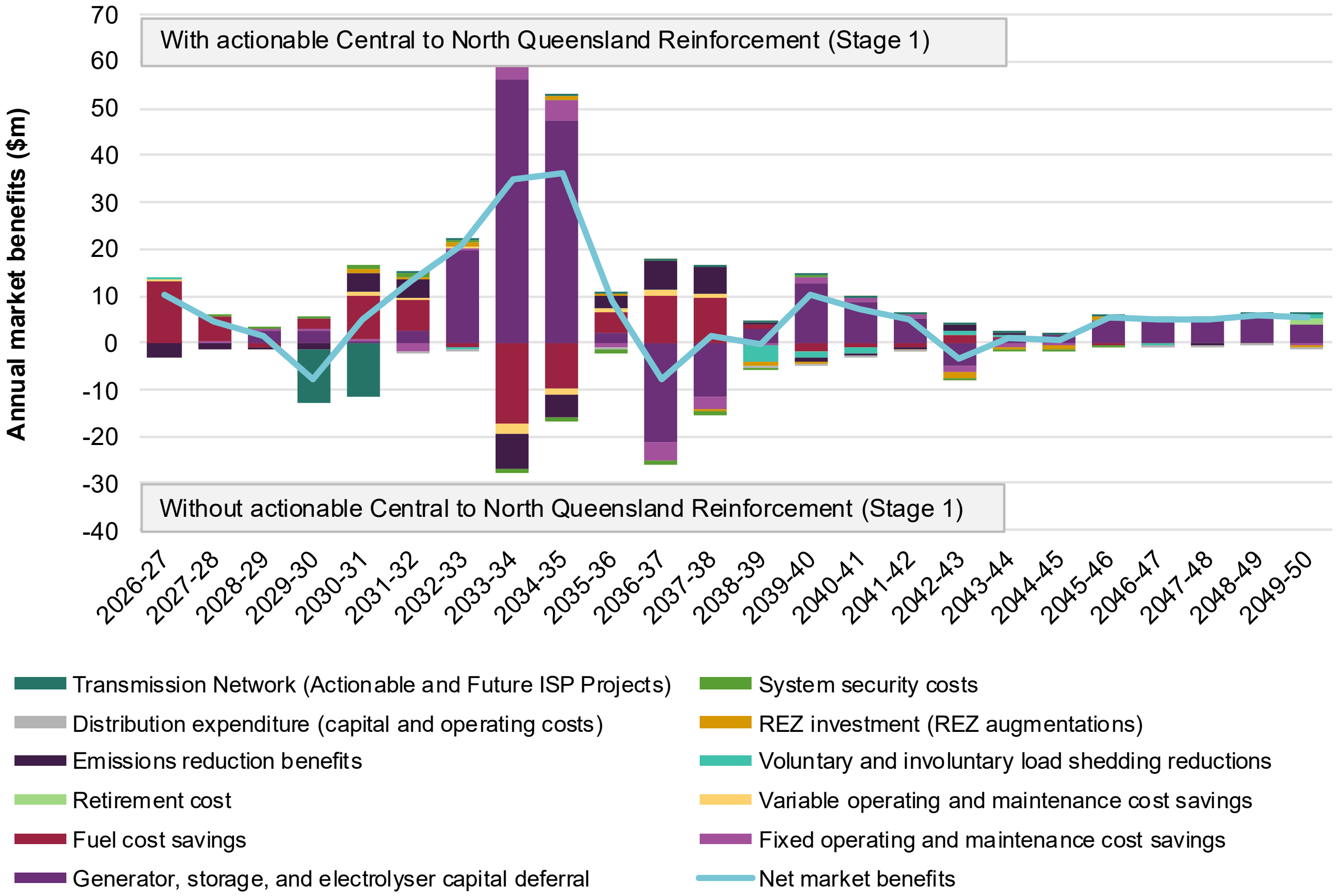
	CDP 4 – with actionable Central to North Queensland Reinforcement (Stage 1)	CDP 5 – without actionable Central to North Queensland Reinforcement (Stage 1)	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.30	0.01
Step Change	29.55	29.58	0.03
Accelerated Transition	42.55	42.47	-0.08
Weighted net market benefits	27.86	27.85	-0.00[B]
Ranking based on weighted net market benefits	1	2	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.
B. WNMB in CDP 4 is $4 million higher than CDP 5, but negligible when rounded to the nearest ten million.

The actionable delivery of Central to North Queensland Reinforcement (Stage 1) has a relatively small impact. In *Step Change*, delivery of the project at actionable timing has relatively small reduction in net market benefit, with small reductions in black coal generation and new build needed in Central and Southern Queensland, but insufficient savings in generation and storage development investment to offset the additional cost for bringing forward delivery of this project at an actionable timing. In *Slower Growth,* the lower net market benefits relative to CDP 5 are less pronounced than in *Step Change*, with the augmentation mainly leading to a minor increase in flow path expenditure and limited material impact on generation development.

In *Accelerated Transition,* however, actionable delivery of this project provides positive net market benefit by allowing higher transfer of existing VRE generation from Northern to Central and Southern Queensland, replacing earlier utility-scale solar development as well as flexible gas usage with benefits offsetting transmission cost. This is demonstrated in **Figure 12**.

Figure 12 Net market benefits of an actionable Central to North Queensland Reinforcement (Stage 1), *Accelerated Transition*



Assessing the regrets associated with not treating Central to North Queensland Reinforcement (Stage 1) as an actionable project

Table 18 highlights the increase in weighted regrets associated with a non-actionable delivery of Central to North Queensland Reinforcement (Stage 1) Project. As discussed in the previous section, delaying this project beyond its actionable window would lead to an increase in total system cost in *Accelerated Transition*, but decreases in the two other scenarios. The regret cost associated with non-actionable delivery is therefore highest in *Accelerated Transition* as delivering the project at its EISD supports the higher demand in that scenario. Nonetheless, the worst weighted regret remains driven by that in *Slower Growth*, meaning CDP 4 and CDP 5 are similarly ranked by this measure.

Table 18 Weighted and worst weighted regrets of CDP 4 and CDP 5 ($ million) – Central to North Queensland Reinforcement (Stage 1)

	CDP 4 – with actionable Central to North Queensland Reinforcement (Stage 1)	CDP 5 – without actionable Central to North Queensland Reinforcement (Stage 1)	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	136	-4
Step Change	101	86	-14
Accelerated Transition	43	65	23
Worst weighted regrets	140	136	-4
Ranking based on worst weighted regrets	5	3	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Gladstone Project

	CQ- GG Option 2
EISD	March 2029
Actionable window length	4 years (actionable in 2024 ISP)
Reported cost[44]	$2,367 million[45] Class 5 (-20% to +30%)
Cost adjusted for transmission cost escalation	$2,442 million (*Slower Growth*, 2028-29) $2,442 million (*Step Change*, 2028-29) $2,480 million (*Accelerated Transition*, 2028-29)
Flow path or REZ	Central Queensland to Gladstone Grid
Capacity increase	2,600 MW forward/500 MW reverse

The Gladstone Project improves supply to the Gladstone Grid sub-region as coal generation retires by increasing the limit on flows from Central Queensland to Gladstone Grid by 2,600 MW. This project was previously identified as an actionable Queensland project in the 2024 ISP and therefore has an actionable window of four years. With Gladstone Power Station announcing a potential closure date of 31 March 2029, Gladstone Project is found optimal at its EISD of March 2029 in the least-cost DP of all three scenarios to provide reliability of supply to the sub-region after this closure.

Assessing the relative market benefits of Gladstone Project via TOOT analysis

Table 19 and **Figure 13** present the relative market benefits associated with the Gladstone Project being delivered at its EISD (2028-29), or not at all. The project delivers around $7,850 million in relative market benefits which are mainly derived from avoided generator and storage capital and fuel costs.

The project reduces the need to build increasing amounts of dispatchable capacity – particularly flexible gas capacity (and its associated gas fuel costs) in Gladstone Grid from 2028-29 onwards to replace the capacity lost from the announced retirement of Gladstone Power Station in the same year. By 2049-50, over 1.5 GW of flexible gas capacity and 10 terawatt

[44] 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

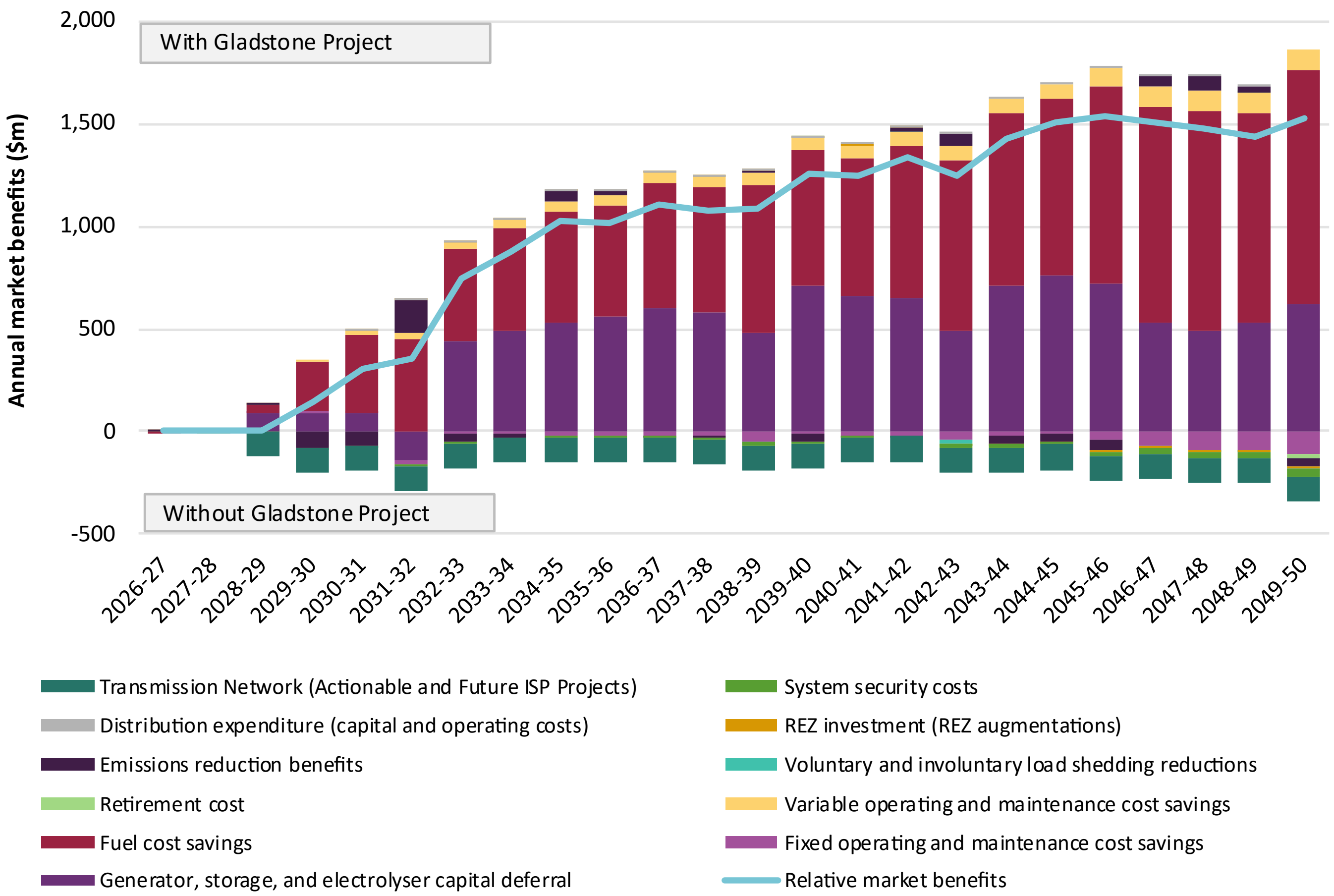
[45] Powerlink has provided a cost estimate for this project as part of its ongoing consideration of options for this flow path. This estimate includes Queensland landholder payments. AEMO adjusted the ISP inputs accordingly to account for this inclusion. This estimate excludes the costs of synchronous condensers.

hours (TWh) of flexible gas consumption is avoided in the Gladstone Grid sub-region through greater access to utility-scale VRE largely based in other Queensland sub-regions.

Table 19 Relative market benefits of Gladstone Project in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	3,684
Fixed operating and maintenance cost savings	-179
Fuel cost savings	5,103
Variable operating and maintenance cost savings	432
Retirement cost	-4
Voluntary and involuntary load shedding reductions	-4
Emissions reduction benefits	3
REZ investment (REZ augmentations)	-6
Distribution expenditure (capital and operating costs)	15
System security costs	-97
Gross market benefits	**8,947**
Transmission Network (Actionable and Future ISP Projects)	-1,096
Total relative market benefits	**7,850**

Figure 13 Annual relative market benefits of Gladstone Project in *Step Change* (2028-29)



Assessing the net market benefits of Gladstone Project as an actionable project

The benefits associated with delivering Gladstone Project at an actionable timing are demonstrated through a comparison between CDP 4, in which the project's delivery is within the actionable window, and CDP 6, in which the project's delivery is outside its actionable window. In both cases, Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South) is delivered as a future project, meaning the project's delay does not inhibit the subsequent project. **Table 20** shows that Gladstone Project would deliver $1.52 billion additional weighted net market benefits when actionable, reducing the otherwise high costs associated with reliability risks if the project was delayed.

Table 20 Comparing net market benefits between CDP 4 and CDP 6 ($ billion) – Gladstone Project

	CDP 4 – with actionable Gladstone Project	CDP 6 – without actionable Gladstone Project	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	9.66	-0.63
Step Change	29.55	28.15	-1.39
Accelerated Transition	42.55	39.92	-2.63
Weighted net market benefits	27.86	26.34	-1.52
Ranking based on weighted net market benefits	1	31	NA

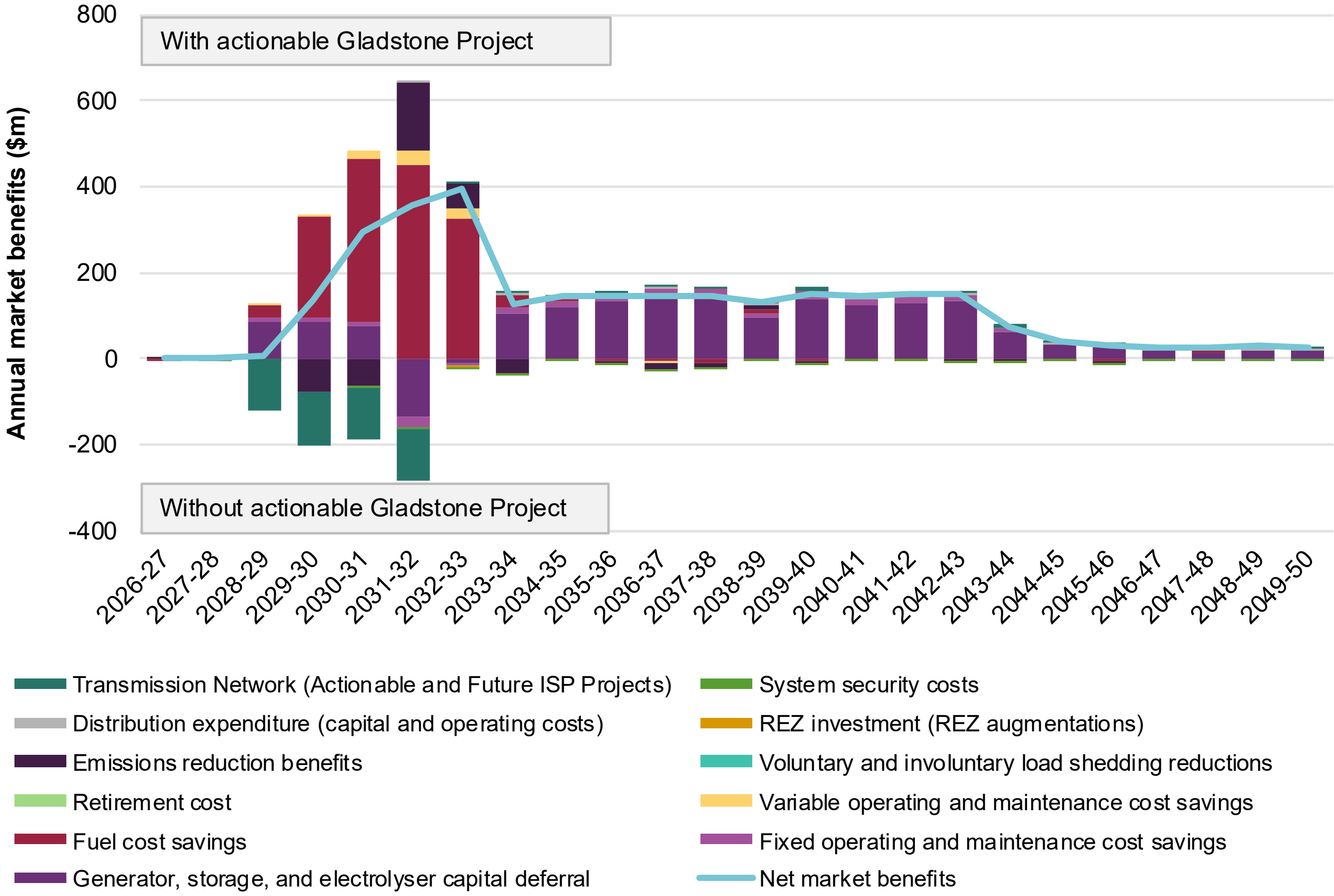
A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Without further augmentation to supply Gladstone Grid following Gladstone Power Station's closure, substantial investments in local generation capacity within the sub-region are required. In *Step Change*, this involves an additional 800 MW of flexible gas, 245 MW of utility-scale solar and 50 MW storage in Gladstone Grid by 2030-31, leading to major generator and storage capital expenditure, fixed operating and maintenance costs, and fuel costs associated with the subsequent increase in flexible gas operation. The annualised net market benefits are shown in **Figure 14.**

Benefits are less pronounced in *Slower Growth*, owing to assumed industrial load closures in Gladstone Grid from 2029-30 onwards in this scenario. In this scenario, 570 MW of additional flexible gas is needed in the region, increasing the generation and storage cost. Nonetheless, Gladstone Project is still shown to deliver benefits in *Slower Growth* to reinforce supply.

Similar types of benefits are observed in *Accelerated Transition*.

Figure 14 Net market benefits of an actionable Gladstone Project, *Step Change*



Assessing the regrets associated with not treating Gladstone Project as an actionable project

Table 21 highlights the increase in weighted regrets associated with a non-actionable delivery of Gladstone Project. As discussed in the previous section, delaying this project beyond its actionable window leads to major increases in cost across all scenarios and an overall increase in worst weighted regret of $613 million. The weighted regret cost is highest in *Accelerated Transition* as delivering the project at its EISD supports the higher demand in that scenario.

Table 21 Weighted and worst weighted regrets of CDP 4 and CDP 6 ($ million) – Gladstone Project

	CDP 4 – with actionable Gladstone Project	CDP 6 – without actionable Gladstone Project	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	310	170
Step Change	101	741	641
Accelerated Transition	43	753	711
Worst weighted regrets	140	753	613
Ranking based on worst weighted regrets	5	30	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Brisbane Area 275 kV Reinforcement

	SQ- CQ Option 7
EISD	June 2032
Actionable window length	2 years (not previously actionable)
Reported cost[46]	$63 million Class 5 (-20% to +30%)
Cost adjusted for transmission cost escalation	$67 million (*Slower Growth*, 2031-32) $68 million (*Step Change*, 2031-32) $70 million (*Accelerated Transition*, 2031-32)
Flow path or REZ	Southern Queensland to Central Queensland
Capacity increase	685 MW forward (summer)/250 MW forward (winter)/0 MW reverse

The Brisbane Area 275 kV Reinforcement provides an increase in export capacity from Southern Queensland to Central Queensland, with a higher uplift during summer. The 2024 ISP and Draft 2026 ISP reflected Queensland Government policy settings and advice from Powerlink at the time, which indicated that constraints in the 275 kV network around the Blackwall, South Pine and Rocklea area would be addressed as part of broader network development and were therefore not explicitly modelled as discrete options. Powerlink has since advised that it should no longer be assumed to proceed and should instead be tested as a separate augmentation project for the 2026 ISP.

The augmentation improves the ability for Northern Queensland, Central Queensland, and Gladstone Grid to be supplied by generation from Southern Queensland and the southern NEM regions. It is found to be optimal at its EISD of June 2032 in the least-cost DPs for *Step Change* and *Accelerated Transition*, and at a non-actionable timing of 2037-38 in the least-cost DP for *Slower Growth*.

Assessing the relative market benefits of Brisbane Area 275 kV Reinforcement via TOOT analysis

The relative market benefits of Brisbane Area 275 kV Reinforcement being delivered at its EISD compared to not building it at all in *Step Change* are shown in **Table 22** and **Figure 15** below. Most of the $407 million in net market benefits associated with the project come from generator capital deferral, as the relatively low existing limit on northerly flows from Southern Queensland to Central Queensland (415 MW in summer and 850 MW in winter) means that, without augmentation, investment in local generation capacity would be required to service demand north of the flow path between Southern Queensland and Central Queensland.

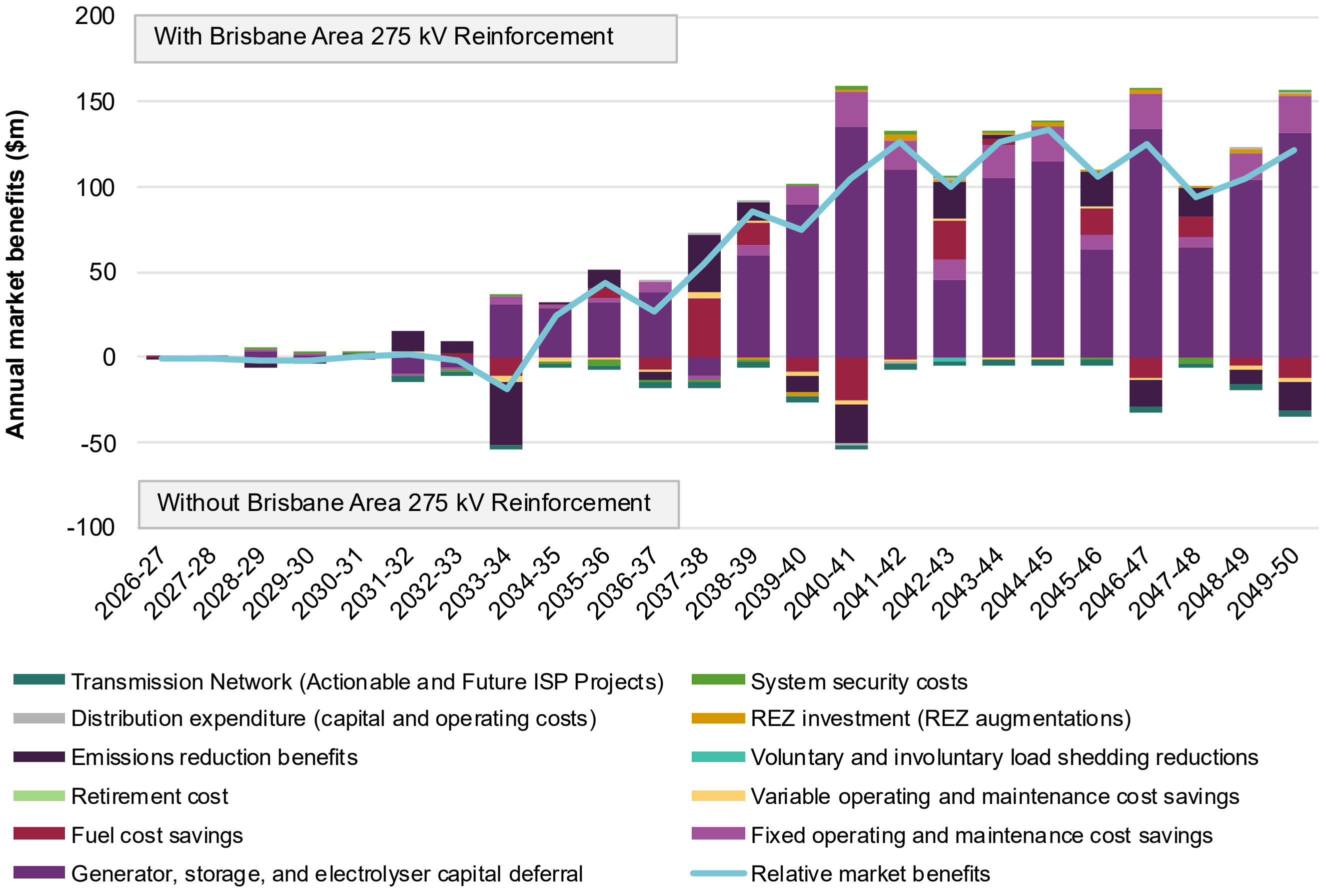
With Brisbane Area 275 kV Reinforcement in place, the development of utility-scale solar and wind in Central New South Wales and Southern Queensland (1.8 GW more by 2039-40, relative to not having the augmentation at all) would be sufficient to ensure demand in the north is being met. However, if the project is not delivered, an additional 500 MW of utility-scale solar and 500 MW of utility-scale wind would be required across Central and Northern Queensland by 2039-40, as well as 600 MW of mid-scale generation in Sydney, Newcastle and Wollongong, leading to a less cost-effective solution overall. Benefits increase steadily through to the 2040s as these generation capacity differences grow.

[46] 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

Table 22 Relative market benefits of Brisbane Area 275 kV Reinforcement in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	369
Fixed operating and maintenance cost savings	53
Fuel cost savings	11
Variable operating and maintenance cost savings	-5
Retirement cost	-0
Voluntary and involuntary load shedding reductions	-1
Emissions reduction benefits	1
REZ investment (REZ augmentations)	4
Distribution expenditure (capital and operating costs)	0
System security costs	-2
Gross market benefits	**430**
Transmission Network (Actionable and Future ISP Projects)	-23
Total relative market benefits	**407**

Figure 15 Annual relative market benefits of Brisbane Area 275 kV Reinforcement in *Step Change* (2031-32)



Assessing the net market benefits of Brisbane Area 275 kV Reinforcement as an actionable project

Table 23 demonstrates the net market benefits associated with delivering Brisbane Area 275 kV Reinforcement at an actionable timing by comparing the net market benefits between CDP 4, which features the project as actionable, and CDP 7, which does not. It shows that an actionable Brisbane Area 275 kV Reinforcement would deliver $10 million more in weighted net market benefits. While these benefits appear relatively small, they equate to approximately 12% of the relatively low capital cost of the project ($68 million in present value terms, in *Step Change*).

Table 23 Comparing net market benefits between CDP 4 and CDP 7 ($ billion) – Brisbane Area 275 kV Reinforcement

	CDP 4 – with actionable Brisbane Area 275 kV Reinforcement	CDP 7 – without actionable Brisbane Area 275 kV Reinforcement	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.29	-0.00
Step Change	29.55	29.54	-0.01
Accelerated Transition	42.55	42.53	-0.02
Weighted net market benefits	27.86	27.85	-0.01
Ranking based on weighted net market benefits	1	3	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Benefits in *Step Change* primarily come from fuel cost savings, where having Brisbane Area 275 kV Reinforcement at an actionable timing would avoid mid-merit gas generation in 2032-33 and 2033-34 that would otherwise be required if it was non-actionable, primarily in Northern Queensland. Similar differences are seen in *Accelerated Transition*, with benefits in this scenario also derived from the deferral of approximately 50 MW of utility-scale wind capacity in Northern Queensland.

Assessing the regrets associated with not treating Brisbane Area 275 kV Reinforcement as an actionable project

The change in regrets associated with delivering Brisbane Area 275 kV Reinforcement at a non-actionable timing is shown in **Table 24** below. While not delivering the project at an actionable timing in *Slower Growth* results in a similar weighted regret, it is shown to be more regretful in both *Step Change* and *Accelerated Transition* by $4 million on a weighted basis. Nonetheless, the worst weighted regret remains driven by that in *Slower Growth*, meaning CDP 4 and CDP 7 are similarly ranked by this measure.

Table 24 Weighted and worst weighted regrets of CDP 4 and CDP 7 ($ million) – Brisbane Area 275 kV Reinforcement

	CDP 4 – with actionable Brisbane Area 275 kV Reinforcement	CDP 7 – without actionable Brisbane Area 275 kV Reinforcement	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	140	0
Step Change	101	105	4
Accelerated Transition	43	47	4
Worst weighted regrets	140	140	0
Ranking based on worst weighted regrets	5	6	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Sydney Ring North (Hunter Transmission Project)

	CNSW-SNW Option 1
EISD	November 2029
Actionable window length	6 years (actionable in 2022 and 2024 ISPs)
Reported cost[47]	$1,364 million Class 5b (±50%)
Cost adjusted for transmission cost escalation	$1,429 million (*Slower Growth*, 2029-30) $1,436 million (*Step Change*, 2029-30) $1,457 million (*Accelerated Transition*, 2029-30)
Flow path or REZ	Central New South Wales to Sydney, Newcastle, and Wollongong (northern limit)
Capacity increase	5,000 MW forward

Sydney Ring North (Hunter Transmission Project) provides a 5,000 MW upgrade to the northern side of the Central New South Wales to Sydney, Newcastle and Wollongong flow path. Sydney Ring North (Hunter Transmission Project) is a pre-requisite for the Sydney Ring South power flow control option. It was identified as an actionable New South Wales project in the 2022 and 2024 ISPs, which gives it an actionable window of six years from its EISD.

In addition, the Sydney Ring South power flow control option only has network impacts until the development of the Sydney Ring South – 500 kV option; though the project has lasting benefits from a total system cost perspective.

The optimal timing of Sydney Ring North (Hunter Transmission Project) is at its EISD of November 2029 across the least-cost DPs for all scenarios (that is, rather than delaying to beyond its six year actionable window), as project helps prepare for the closure of coal-fired power stations in the Sydney, Newcastle and Wollongong area.

Assessing the relative market benefits of Sydney Ring North (Hunter Transmission Project) and Sydney Ring South via TOOT analysis

Sydney Ring North (Hunter Transmission Project) is a pre-requisite of another flow path augmentation option (Sydney Ring South power flow control option); hence delivery of that project must also be excluded when undertaking TOOT analysis. **Table 25** and **Figure 16** present the relative market benefits of these projects in *Step Change*.

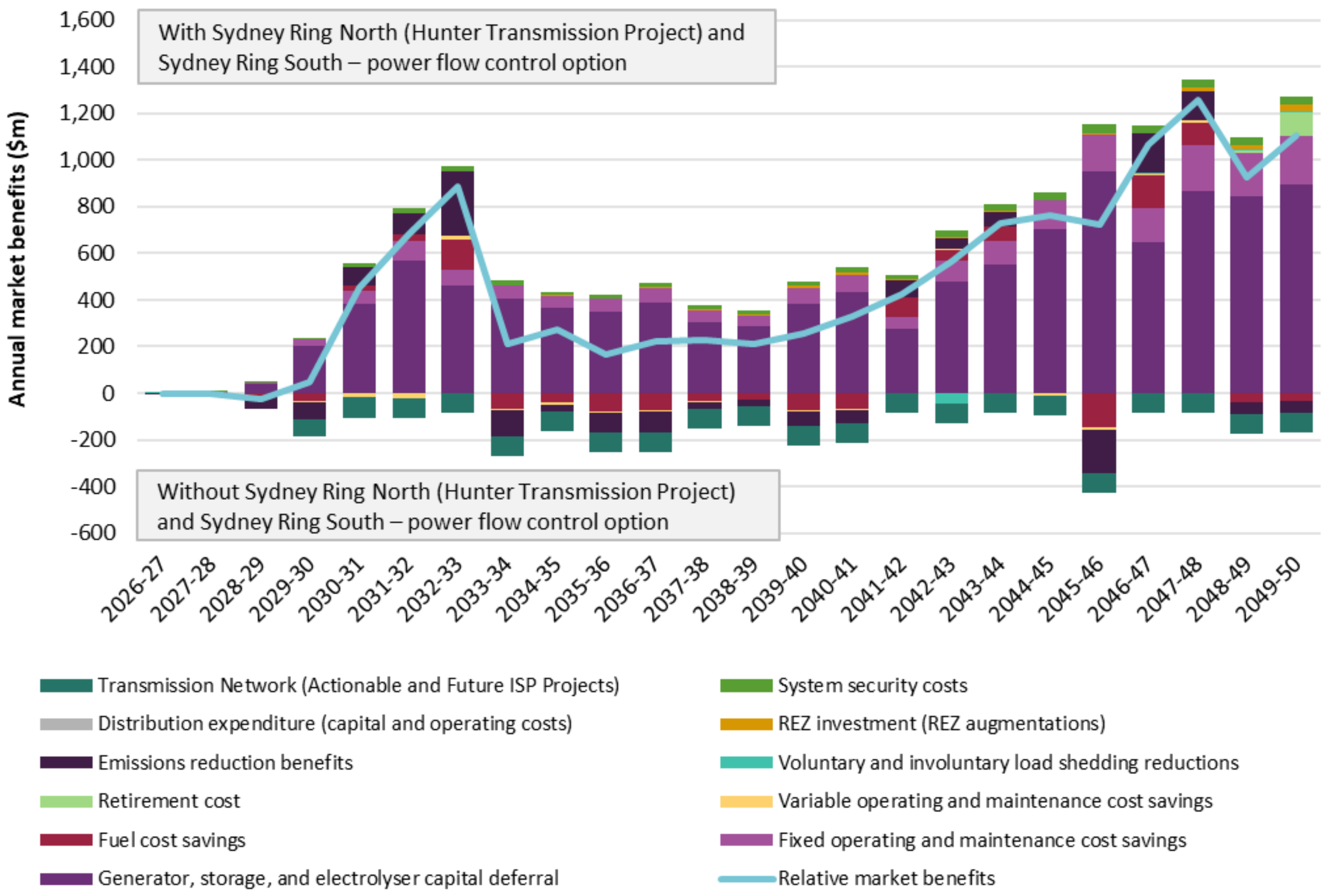
Overall, the projects contribute around $3,836 million to the ODP's net market benefits in *Step Change* reducing generation and storage capital costs and providing savings for operating and maintenance costs.

[47] 'Reported cost' refers to the estimate prepared by AEMO and reviewed by EnergyCo. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

Table 25 Relative market benefits of Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option in *Step Change* (2029-30 and 2030-31 respectively)

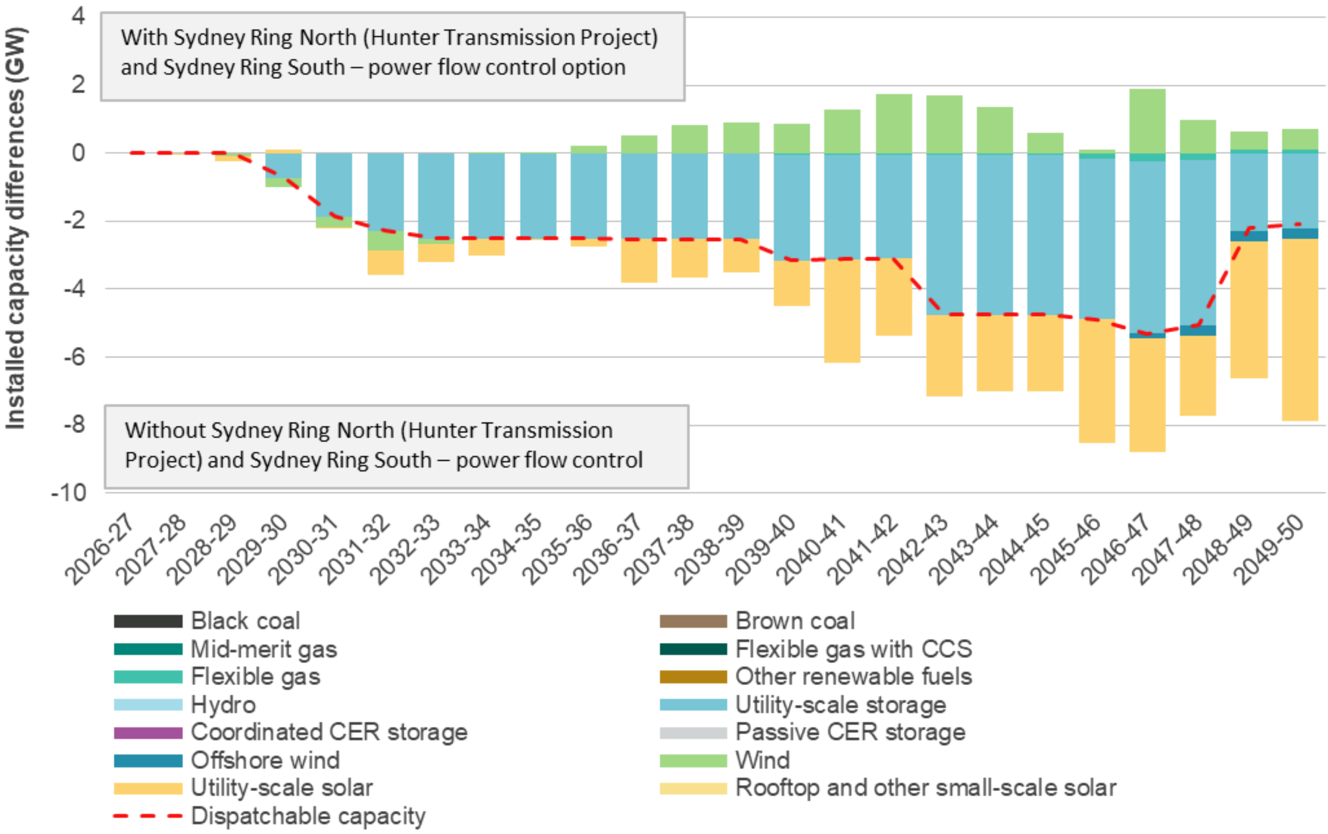
Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	3,778
Fixed operating and maintenance cost savings	639
Fuel cost savings	-59
Variable operating and maintenance cost savings	-49
Retirement cost	21
Voluntary and involuntary load shedding reductions	-11
Emissions reduction benefits	-0
REZ investment (REZ augmentations)	40
Distribution expenditure (capital and operating costs)	-5
System security costs	171
Gross market benefits	**4,525**
Transmission Network (Actionable and Future ISP Projects)	-689
Total relative market benefits	**3,836**

Figure 16 Annual relative market benefits of Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option in *Step Change* (2029-30 and 2030-31 respectively)



As shown in **Figure 17,** delivery of these projects at actionable timings compared to not at all avoids around 2.5 GW of utility-scale storage in the 2030s and 4.7 GW by 2042-43. Without the projects, additional utility-scale solar resources would be required in Sydney, Newcastle and Wollongong over the period to the early 2040s. By delivering the network projects, lower cost utility-scale solar and wind in Central New South Wales, Northern New South Wales, and Queensland can be developed and operated from the mid-2030s instead.

Figure 17 Comparison of capacity with and without Sydney Ring North (Hunter Transmission Project) and Sydney Ring South power flow control option in *Step Change* (2029-30 and 2030-31)



Assessing the net market benefits of Sydney Ring North (Hunter Transmission Project) as an actionable project

The benefits of Sydney Ring North (Hunter Transmission Project) as an actionable project can be assessed by comparing CDP 10, which delivers the project at an actionable timing, against CDP 11, which delays its delivery beyond its actionable window. In both CDPs, Sydney Ring South power flow control option is delayed after its actionable window to isolate the benefits of Sydney Ring North (Hunter Transmission Project).

As shown in **Table 26**, an actionable Sydney Ring North (Hunter Transmission Project) delivers benefits across all scenarios and has a weighted net market benefit of $3.22 billion. These benefits are primarily driven by savings in generator and storage capital expenditure, and to a lesser extent, fixed operating and maintenance costs and fuel costs.

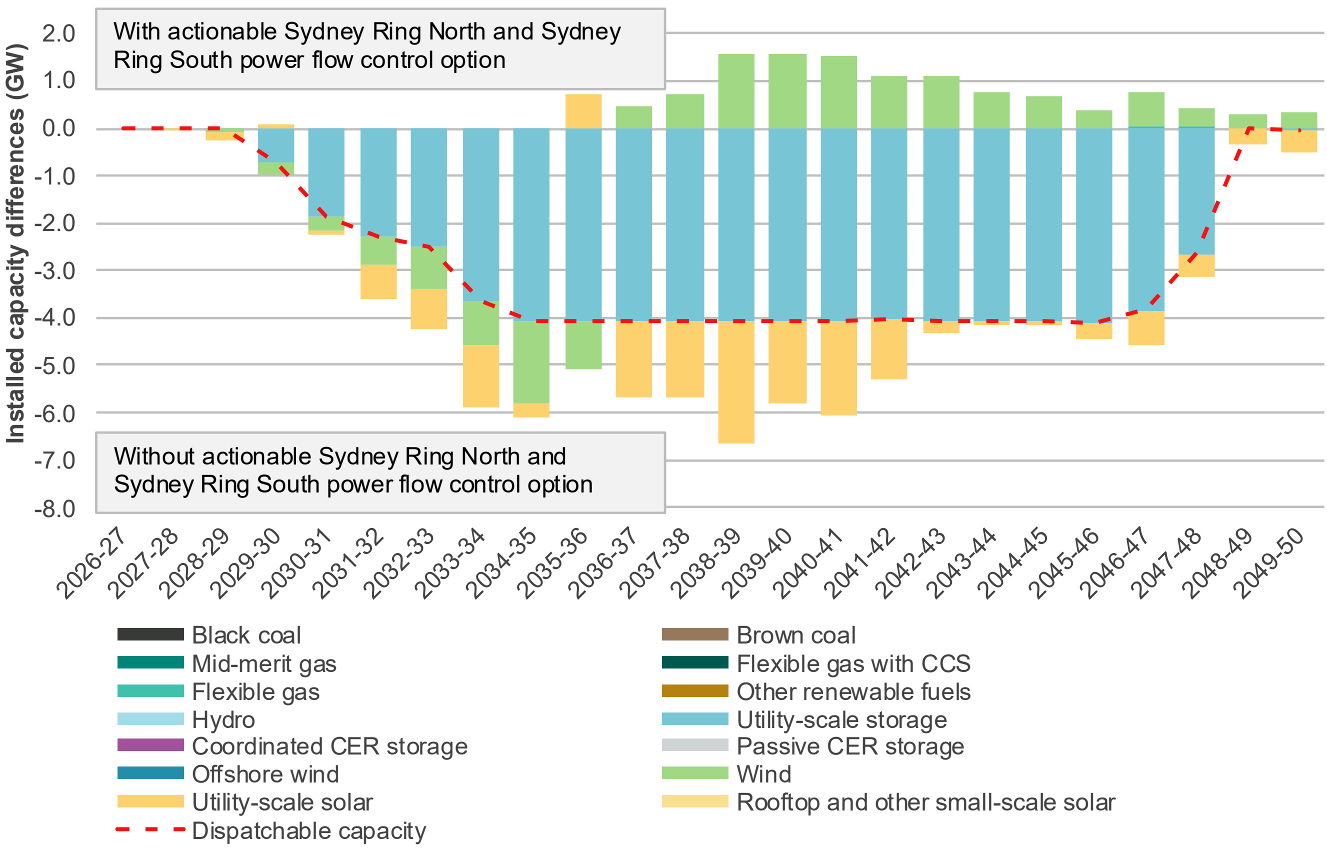
Table 26 Comparing net market benefits between CDP 10 and CDP 11 ($ billion) – Sydney Ring North (Hunter Transmission Project)

	CDP 10 – with actionable Sydney Ring North (Hunter Transmission Project)	CDP 11 – without actionable Sydney Ring North (Hunter Transmission Project)	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.37	8.65	-1.73
Step Change	29.33	24.65	-4.68
Accelerated Transition	42.15	39.94	-2.21
Weighted net market benefits	27.67	24.46	-3.22
Ranking based on weighted net market benefits	14	32	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change*, delaying the project to after its actionable window would require an additional 4 GW of utility-scale storage in Sydney, Newcastle, and Wollongong, to be developed by the mid-2030s, along with over 900 MW of additional VRE capacity by 2034-35. This is illustrated in **Figure 18**. Delivering the project at a non-actionable timing also delays the Sydney Ring South power flow control option, which would prohibit increased flows from Southern New South Wales resulting in additional VRE to be developed in Queensland, peaking at 830 MW of wind and around 950 MW of solar by 2034-35.

Figure 18 Comparison of capacity with and without actionable Sydney Ring North (Hunter Transmission Project) in *Step Change*



The reduction in relative market benefits is less pronounced in *Accelerated Transition*, as the faster New South Wales coal retirements and higher electricity consumption featured in this scenario drive more and earlier build of utility-scale storages, VRE, and flexible gas compared with *Step Change,* that the project would not be able to defer. In *Accelerated Transition,* compared with *Step Change*, even with an actionable Sydney Ring North (Hunter Transmission Project), additional battery capacity (1.1 GW), flexible gas (another 1.1 GW) and VRE (around 3.6 GW) is developed by 2034-35 in Sydney, Newcastle and Wollongong.

In *Accelerated Transition*, a delayed Sydney Ring North (Hunter Transmission Project) to after its actionable window would require an additional 650 MW of utility-scale storage, and 1.4 GW of additional wind by 2034-35 in New South Wales. Without the project, 1.4 GW of additional solar is also developed in Sydney, Newcastle and Wollongong which would otherwise be deferred to the mid-2040s. These additional generation and storage investments drive an overall increase in cost of $2.21 billion in this scenario.

Assessing the regrets associated with not treating Sydney Ring North (Hunter Transmission Project) as an actionable project

The weighted regrets of an actionable and non-actionable Sydney Ring North (Hunter Transmission Project) are presented in **Table 27**. Delaying the project until after its actionable window is regretful in all scenarios, with the worst weighted regret driven by under-investment in *Step Change* – from $200 million to $2,354 million.

Table 27 Weighted and worst weighted regrets of CDP 10 and CDP 11 ($ million) – Sydney Ring North (Hunter Transmission Project)

	CDP 10 – with actionable Sydney Ring North (Hunter Transmission Project)	CDP 11 – without actionable Sydney Ring North (Hunter Transmission Project)	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	116	583	467
Step Change	200	2,354	2,154
Accelerated Transition	151	748	597
Worst weighted regrets	200	2,354	2,154
Ranking based on worst weighted regrets	13	32	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Sydney Ring South

	Power flow control option [CNSW-SNW Option 2d]	500 kV transmission option (Stage 1) [CNSW-SNW Option 3 – Stage 1]	500 kV transmission option (Stage 2) [CNSW-SNW Option 3 – Stage 2]
EISD	July 2030	July 2033	July 2033
Actionable window length	4 years (actionable in 2024 ISP)		
Reported cost[48]	$261 million[49] Class 5(±50%)	$1,780 million[49] Class 5(±50%)	$580 million[49] Class 5(±50%)
Cost adjusted for transmission cost escalation	$269 million (*Slower Growth*, 2030-31) $269 million (*Step Change*, 2030-31) $274 million (*Accelerated Transition*, 2030-31)	$2,068 million (*Slower Growth*, 2033-34) $2,083 million (*Step Change*, 2033-34) $2,127 million (*Accelerated Transition*, 2033-34)	$615 million (*Slower Growth*, 2033-34) $624 million (*Step Change*, 2033-34) $637 million (*Accelerated Transition*, 2033-34)
Flow path or REZ	Central New South Wales to Sydney, Newcastle and Wollongong (southern limit)		
Capacity increase	N/A (this option improves power flow sharing between the northern and southern segments of the CNSW to SNW flow path, allowing more generation to be transferred from SNSW to SNW)	1,300 MW forward	2,300 MW forward

Like Sydney Ring North (Hunter Transmission Project), Sydney Ring South improves supply to the Sydney, Newcastle and Wollongong load centre, which is increasingly important following New South Wales coal plant closures and to accommodate growth in electricity consumption. Sydney Ring South project (with power flow control option as the ISP preferred solution) was previously found actionable in the 2024 ISP, giving it an actionable window length of four years.

The smaller power flow control option improves the transfer capacity along the Central New South Wales to Sydney, Newcastle and Wollongong flow path. While this does not result in a direct increase in transfer capacity, it improves the power flow sharing between the northern and southern segments of the Central New South Wales to Sydney, Newcastle and Wollongong flow path, allowing more generation to be transferred into Sydney, Newcastle and Wollongong from Southern New South Wales. It is found to be optimal at its EISD of July 2030 in all three scenarios, as opposed to delaying by at least four years to be outside its actionable window.

A subsequent, larger 500 kV transmission option for Sydney Ring South is identified optimal at an actionable timing in the least-cost DPs for *Step Change* and *Accelerated Transition*, and immediately after its actionable window in July 2037 in *Slower Growth*. This option would provide a further 3,600 MW of transfer capacity from Central New South Wales into Sydney, Newcastle and Wollongong across two stages. Both options are considered to have four-year actionable windows since both options have been explored to address the same identified need as the power flow control option.

[48] 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[49] The $2025 cost of this option $2,621 million, consisting of $261 million (power flow control option) and $2,360 million (500 kV transmission option) was provided by Transgrid for the 2025 *Electricity Network Options Report* and has been modelled in the 2026 ISP. Transgrid's Sydney Ring South Project Assessment Draft Report (PADR) identified the preferred option (PADR Option 6) with a capital cost estimate of $3,519 million ($2026). AEMO notes that four effectively first-equal ranked options (PADR Option 3, 4, 5, 6) have capital cost estimates between $3,353 million ($2026) and $4,915 million ($2026).

Assessing the relative market benefits of Sydney Ring South power flow control option via TOOT analysis

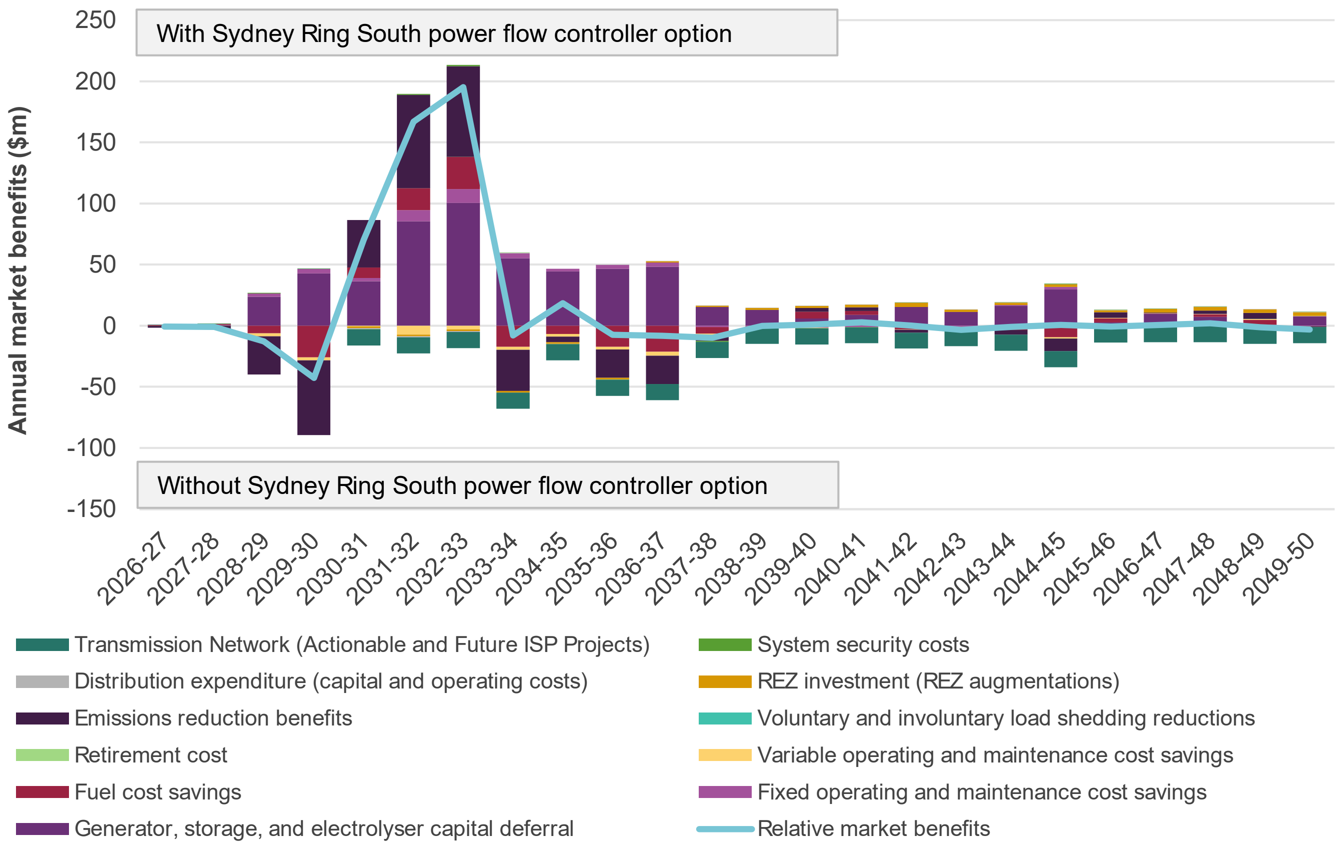
As seen in **Table 28**, the relative market benefits of Sydney Ring South power flow control option in *Step Change* amount to $216 million, compared to not progressing this option at all. Its gross benefits come primarily from generator and storage capital deferral savings.

Figure 19 presents the annual relative market benefits. These benefits are greatest in the medium term, though reduce in the longer term with the development of the 500 kV transmission option. The ODP and the Sydney Ring South power flow control option TOOT in *Step Change* have both stages of the larger Sydney Ring South – 500 kV transmission option (Stages 1 and 2) developed by 2033-34.

Table 28 Relative market benefits of Sydney Ring South power flow control option in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	324
Fixed operating and maintenance cost savings	24
Fuel cost savings	-22
Variable operating and maintenance cost savings	-16
Retirement cost	0
Voluntary and involuntary load shedding reductions	-1
Emissions reduction benefits	2
REZ investment (REZ augmentations)	4
Distribution expenditure (capital and operating costs)	-1
System security costs	2
Gross market benefits	**316**
Transmission Network (Actionable and Future ISP Projects)	-99
Total relative market benefits	**216**

Figure 19 Annual relative market benefits of Sydney Ring South power flow control option in *Step Change* (2030-31)



The development of Sydney Ring South power flow control option allows for improved sharing of electricity between the northern and southern segments of the Central New South Wales to Sydney, Newcastle and Wollongong flow path, effectively allowing more generation into Sydney, Newcastle and Wollongong from Southern New South Wales and Victoria. In the absence of the Sydney Ring South power flow control option, more wind development within Sydney, Newcastle and Wollongong is required to meet demand over the 2030s. Most of this additional wind capacity is located in the Hunter-Central Coast REZ.

Assessing the net market benefits of Sydney Ring South power flow control option as an actionable project

A comparison of CDP 4, which has Sydney Ring South power flow control option as an actionable project, with CDP 10, which delays it to a non-actionable timing, demonstrates the benefits of this project. As discussed under the Sydney Ring North (Hunter Transmission Project) subsection, the power flow control option provides no net market benefits if delayed to after the delivery of the larger Sydney Ring South – 500 kV transmission option.

Table 29 shows that delivery of Sydney Ring South power flow control option at an actionable timing ahead of the 500 kV transmission option would yield positive benefits in *Step Change* and *Accelerated Transition*, but not in *Slower Growth*. The project delivers $180 million more in weighted net market benefits when delivered at its EISD.

Table 29 Comparing net market benefits between CDP 4 and CDP 10 ($ billion) – Sydney Ring South power flow control option

	CDP 4 – with actionable Sydney Ring South power flow control option	CDP 10 – without actionable Sydney Ring South power flow control option	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.37	0.09
Step Change	29.55	29.33	-0.22
Accelerated Transition	42.55	42.15	-0.40
Weighted net market benefits	27.86	27.67	-0.18
Ranking based on weighted net market benefits	1	14	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change,* the main sources of benefits are generator and storage capital deferral. The power flow control option enables 350 MW of VRE developments south of Sydney, Newcastle and Wollongong by 2029-30. Without the option at an actionable timing, an additional 370 MW of wind capacity is required in Sydney, Newcastle and Wollongong by 2029-30.

In *Accelerated Transition*, without an actionable power flow control option, higher generator and storage capital expenditure would be incurred (additional 450 MW of storage capacity in Sydney, Newcastle and Wollongong developed in 2031-32) and increased gas use resulting in higher fuel costs in Sydney, Newcastle and Wollongong over the period to 2032-33.

In *Slower Growth*, the power flow control option is not as beneficial to be delivered ahead of a 500 kV transmission option, given the assumed closure of some major industrial loads, which delays the benefits for early augmentation.

Assessing the regrets associated with not treating Sydney Ring South power flow control option as an actionable project

As seen in **Table 30**, delaying Sydney Ring South power flow control option to a non-actionable timing leads to increased under-investment regret in *Step Change* and *Accelerated Transition*.

Table 30 Weighted and worst weighted regrets of CDP 4 and CDP 10 ($ million) – Sydney Ring South power flow control option

	CDP 4 – with actionable Sydney Ring South power flow control option	CDP 10 – without actionable Sydney Ring South power flow control option	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	116	-24
Step Change	101	200	99
Accelerated Transition	43	151	109
Worst weighted regrets	140	200	60
Ranking based on worst weighted regrets	5	13	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the relative market benefits of Sydney Ring South – 500 kV transmission option via TOOT analysis

AEMO has also examined the potential benefits of the larger Sydney Ring South – 500 kV transmission option (Stage 1 and Stage 2) as an actionable project compared to not delivering it at all.

As seen in **Table 31**, the relative market benefits of Sydney Ring South – 500 kV transmission option in *Step Change* amount to $2,991 million. Its gross benefits come primarily from generator and storage capital deferral savings. The project instead allows for greater utilisation of existing hydro and mid-merit gas generation, as well as offshore wind capacity built as part of the Victorian Offshore Wind Target to service demand in Sydney, Newcastle and Wollongong.

Figure 20 presents the annual relative market benefits. These increase over time, especially from 2038-39 when the project avoids flexible gas builds (the majority in New South Wales) as well as up to 3.4 GW of storage capacity in New South Wales over the 2040s. The projects also avoid additional wind capacity from 2032-33 onwards, mostly in New South Wales. This is particularly evident in the New England REZ, and Hunter-Central Coast REZ within Sydney, Newcastle and Wollongong, where it avoids 2.3 GW by 2037-38, swapping it instead for utility-scale solar. The change in capacity development is shown in **Figure 21**.

Table 31 Relative market benefits of Sydney Ring South – 500 kV transmission option in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	3,239
Fixed operating and maintenance cost savings	478
Fuel cost savings	8
Variable operating and maintenance cost savings	-61
Retirement cost	0
Voluntary and involuntary load shedding reductions	42
Emissions reduction benefits	0
REZ investment (REZ augmentations)	8
Distribution expenditure (capital and operating costs)	-0
System security costs	34
Gross market benefits	**3,749**
Transmission Network (Actionable and Future ISP Projects)	-759
Total relative market benefits	**2,991**

Figure 20 Annual relative market benefits of Sydney Ring South – 500 kV transmission option in *Step Change* (2033-34)

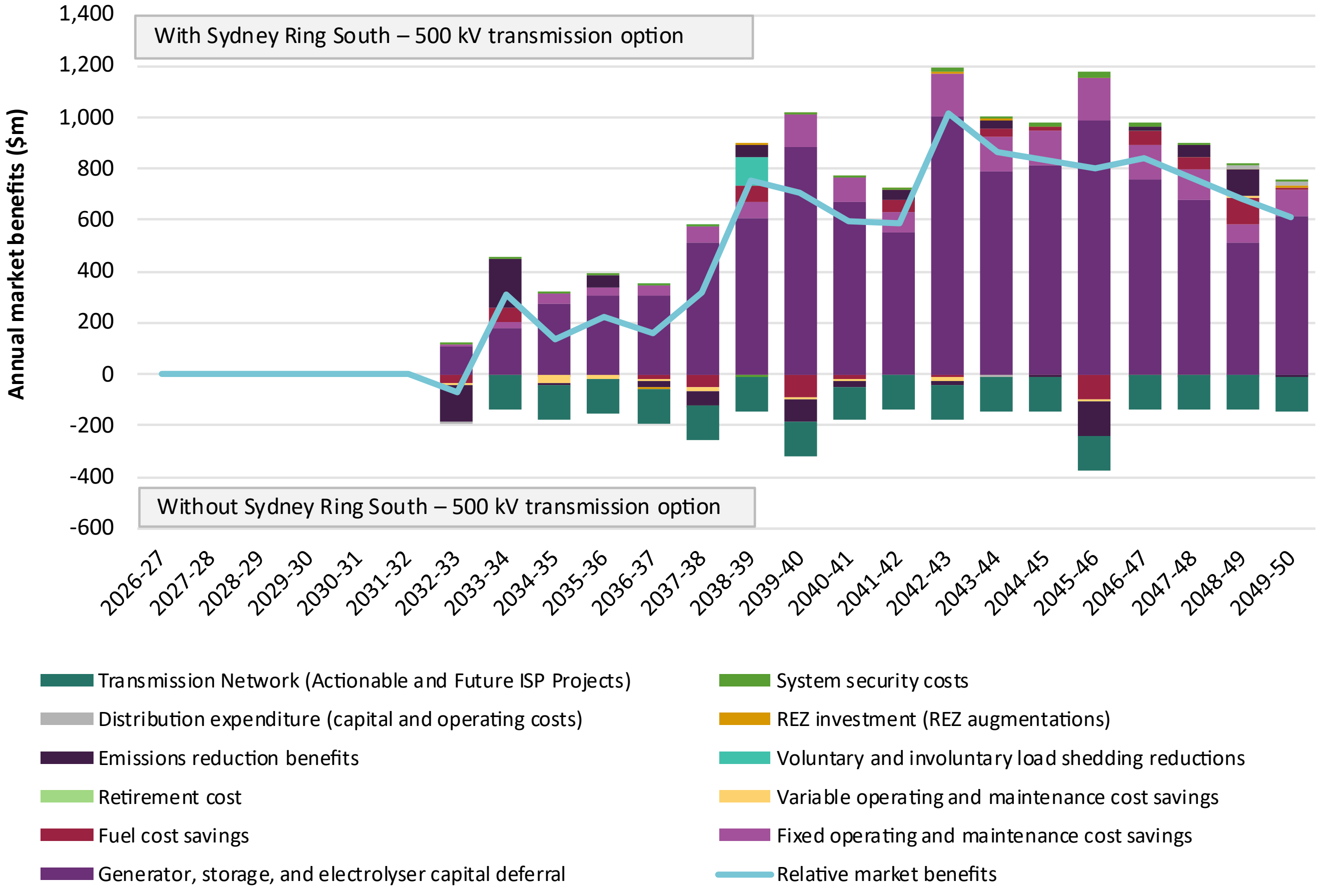
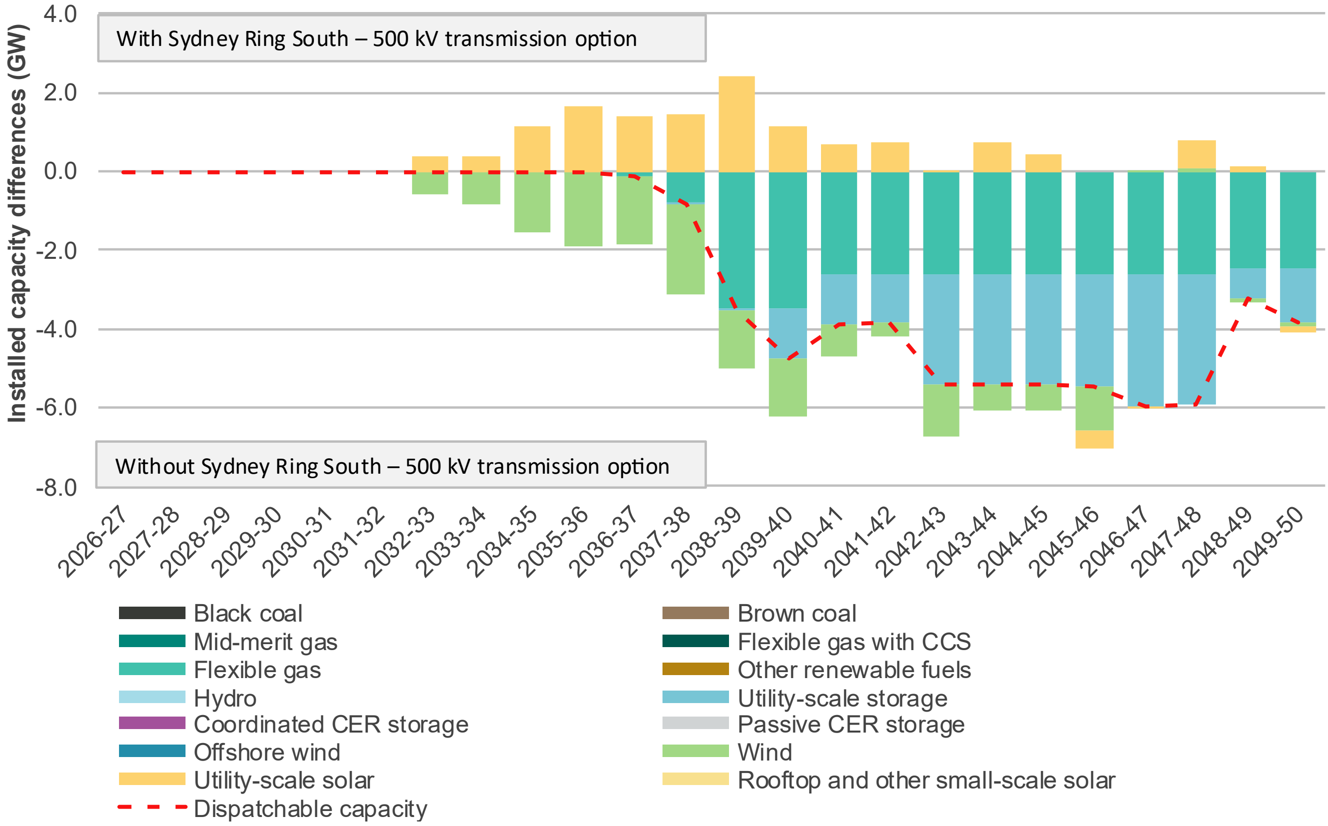


Figure 21 Comparison of capacity with and without Sydney Ring South – 500 kV transmission option in *Step Change* (2033-34)



Assessing the net market benefits of Sydney Ring South – 500 kV transmission option as an actionable project

A comparison between CDP 4, which has Stage 1 and 2 actionable, and CDP 12, which has neither stage as actionable, enables this actionability assessment (with both having the power flow control option installed first). As shown in **Table 32**, the project provides positive net market benefits at its EISD in both *Step Change* and *Accelerated Transition*, but not in *Slower Growth.* Across scenarios, the project provides consumers $220 million more weighted net market benefits when delivered at EISD.

Table 32 Comparing net market benefits between CDP 4 and CDP 12 ($ billion) – Sydney Ring South – 500 kV transmission option

	CDP 4 – with actionable Sydney Ring South – 500 kV transmission option	CDP 12 – without actionable Sydney Ring South – 500 kV transmission option	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.38	0.09
Step Change	29.55	29.08	-0.47
Accelerated Transition	42.55	42.43	-0.12
Weighted net market benefits	27.86	27.63	-0.22
Ranking based on weighted net market benefits	1	17	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Delaying the project in *Step Change* leads to increased generation and storage capital expenditure, as an additional 1.8 GW of wind capacity, mostly distributed between New South Wales sub-regions (including in Sydney, Newcastle and Wollongong), is required by 2035-36. Delivering the project at its actionable timing instead allows for greater utilisation of existing hydro and mid-merit gas generation, as well as offshore wind capacity built as part of the Victorian Offshore Wind Target and solar in Central New South Wales to service demand in Sydney, Newcastle and Wollongong.

In *Accelerated Transition,* the project's main source of benefits of the project at an actionable timing is avoiding between 0.6 GW and 1.4 GW of wind capacity between 2034-35 and 2037-38 that is otherwise developed across New South Wales and Queensland.

In *Slower Growth,* reduced industrial loads and lesser load growth means that the project does not deliver net market benefits at an actionable timing.

Assessing the regrets associated with not treating Sydney Ring South – 500 kV transmission option as an actionable project

As seen in **Table 33**, delaying Sydney Ring South – 500 kV transmission option to a non-actionable timing leads to increased regrets in *Step Change* and *Accelerated Transition*. Overall, it results in an increase in worst weighted regret of $177 million, which comes from the under-investment in transmission in *Step Change.*

Table 33 Weighted and worst weighted regrets of CDP 4 and CDP 12 ($ million) – Sydney Ring South – 500 kV transmission option

	CDP 4 – with actionable Sydney Ring South – 500 transmission kV option	CDP 12 – without actionable Sydney Ring South – 500 kV transmission option	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	115	-25
Step Change	101	317	216
Accelerated Transition	43	76	33
Worst weighted regrets	140	317	177
Ranking based on worst weighted regrets	5	20	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Central-West Orana REZ Expansion

	N3 Option 1
EISD	March 2033
Actionable window length	2 years (not previously actionable)
Reported cost[50]	$855 million Class 5b (±50%)
Cost adjusted for transmission cost escalation	$907 million (*Slower Growth*, 2032-33) $915 million (*Step Change*, 2032-33) $937 million (*Accelerated Transition*, 2032-33)
Flow path or REZ	Central-West Orana REZ
Capacity increase	1,500 MW

The Central-West Orana REZ is electrically close to the Sydney, Newcastle and Wollongong load centre and has moderate to high-quality wind and solar resources. The Central-West Orana REZ Expansion would augment the committed Central-West Orana REZ Network Infrastructure Project by 1,500 MW. The project has an EISD of March 2033 and the Central-West Orana REZ Network Infrastructure Project is a pre-requisite.

Central-West Orana REZ Expansion enables additional VRE capacity to be built in the Central-West Orana REZ to export into the rest of the NEM as energy demand in the Sydney, Newcastle and Wollongong subregion continues to grow and existing coal generators retire. It is assumed to expand the Access Scheme[51] associated with the Central-West Orana REZ, which has a maximum connection limit of 7.7 GW of new VRE generation and storage without this project.

The project is found to be optimal if delivered at its EISD of 2032-33 in the least-cost DPs for *Step Change* and *Accelerated Transition*, and beyond its actionable window in 2039-40 in the least-cost DP for *Slower Growth*.

Assessing the relative market benefits of Central-West Orana REZ Expansion via TOOT analysis

Table 34 and **Figure 22** present the relative market benefits of delivering Central-West Orana REZ Expansion at an actionable timing in *Step Change* compared with not building it at any time in the outlook period. Of the $456 million in total benefits identified, the majority arises from generator and storage capital cost savings, as well as reductions in maintenance and fuel costs. Additional benefits are associated with avoided REZ investment and lower distribution network expenditure.

Without the increase in export capacity to facilitate more VRE capacity in Central-West Orana REZ, increased wind and utility-scale solar development in other New South Wales REZs, including New England, alongside the deployment of an additional 2 GW of mid-scale generation across the state would be needed. This outcome would necessitate further expansion of the distribution network.

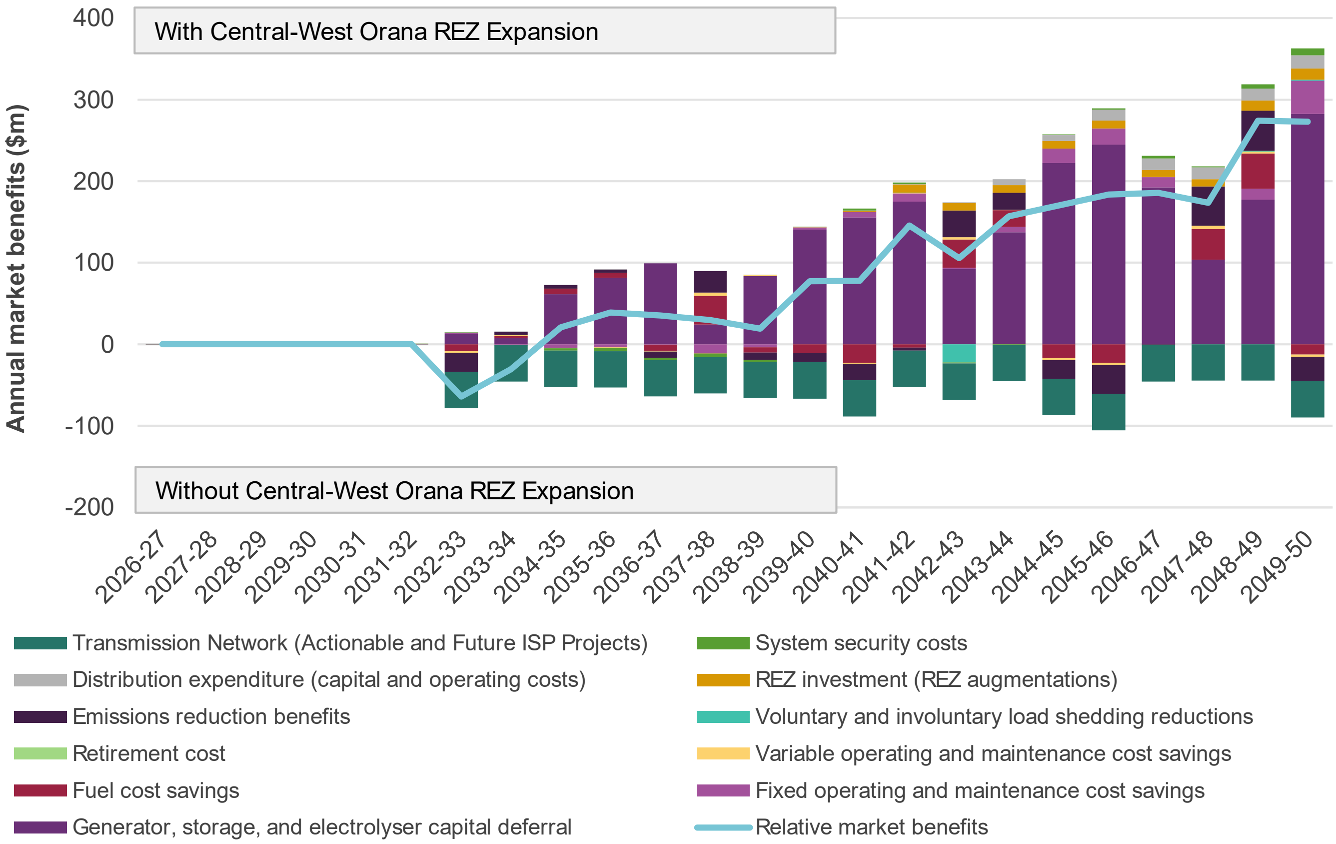
[50] 'Reported cost' refers to the estimate prepared by AEMO and reviewed by EnergyCo. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[51] Access schemes are a key part of the New South Wales Electricity Infrastructure Investment (EII) Act and support the coordination of renewable energy and storage investment in REZs. Generation and storage projects that seek to connect to the network infrastructure where a REZ access scheme applied may be subject to access rights – either through application or competitive tender

Table 34 Relative market benefits of Central-West Orana REZ Expansion in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	662
Fixed operating and maintenance cost savings	21
Fuel cost savings	19
Variable operating and maintenance cost savings	1
Retirement cost	0
Voluntary and involuntary load shedding reductions	-6
Emissions reduction benefits	0
REZ investment (REZ augmentations)	22
Distribution expenditure (capital and operating costs)	20
System security costs	-2
Gross market benefits	**737**
Transmission Network (Actionable and Future ISP Projects)	-280
Total relative market benefits	**456**

Figure 22 Annual relative market benefits of Central-West Orana REZ Expansion in *Step Change* (2033-34)



Assessing the net market benefits of Central-West Orana REZ Expansion as an actionable project

The benefits of Central-West Orana REZ Expansion as an actionable project can be assessed through a comparison between CDP 4, which features delivery of Central-West Orana REZ Expansion at its EISD, and CDP 14, which features the project's delivery at a non-actionable timing. **Table 35** shows that an actionable project would deliver an increase in weighted net market benefits of $20 million, with the benefits mostly accumulating in *Step Change*.

Table 35 Comparing net market benefits between CDP 4 and CDP 14 ($ billion) – Central-West Orana REZ Expansion

	CDP 4 – with actionable Central-West Orana REZ Expansion	CDP 14 – without actionable Central-West Orana REZ Expansion	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.43	0.14
Step Change	29.55	29.43	-0.12
Accelerated Transition	42.55	42.52	-0.03
Weighted net market benefits	27.86	27.83	-0.02
Ranking based on weighted net market benefits	1	5	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

The greater impact observed in *Step Change* reflects the additional capital expenditure required to develop utility-scale wind in the New England REZ when the project is delayed. Overall, net market benefits increase due to a $120 million cost reduction from delivering the Central-West Orana REZ Expansion at actionable timing in *Step Change*. This is primarily driven by deferring a significant portion of VRE development in the less cost-effective Hunter-Central Coast and New England REZs and reducing reliance on black coal generation.

In *Accelerated Transition*, there is a greater development trajectory for VRE generation in New South Wales given the higher energy demand and earlier coal generator retirements in this scenario, however building the project at its EISD does allow for flexible gas to be replaced by VRE generation from the Central-West Orana REZ.

In *Slower Growth*, delivering the project at an actionable timing does not significantly alter the generation capacity development schedule of New South Wales in the 2030s, indicating that in this scenario, unlocking additional capacity in the Central-West Orana REZ earlier is not so valuable.

Assessing the regrets associated with not treating Central-West Orana REZ Expansion as an actionable project

The change in regrets associated with delivering Central-West Orana REZ Expansion to a non-actionable timing is shown in **Table 36**. While there is an increase in regret associated with under-investment in *Step Change* and *Accelerated Transition*, the change in weighted regrets of $39 million between both CDP 4 and CDP 14 in *Slower Growth* indicates a risk of over-investment in this scenario.

Table 36 Weighted and worst weighted regrets of CDP 4 and CDP 14 ($ million) – Central-West Orana REZ Expansion

	CDP 4 – with actionable Central-West Orana REZ Expansion	CDP 14 – without actionable Central-West Orana REZ Expansion	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	101	-39
Step Change	101	156	55
Accelerated Transition	43	50	7
Worst weighted regrets	140	156	15
Ranking based on worst weighted regrets	5	9	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Switching Station Near Wondalga

	SNSW-CNSW Option 5
EISD	December 2030[52]
Actionable window length	2 years (not previously actionable)
Reported cost[53]	$220 million Class 5b (±50%)
Cost adjusted for transmission cost escalation	$230 million (*Slower Growth*, 2030-31) $232 million (*Step Change*, 2030-31) $235 million (*Accelerated Transition*, 2030-31)
Flow path or REZ	Southern New South Wales to Central New South Wales
Capacity increase	450 MW forward/450 MW reverse

The Switching Station Near Wondalga project is a new switching station that complements the committed HumeLink project and provides an additional 450 MW of transfer capacity to the Southern New South Wales to Central New South Wales flow path. It provides load centres in New South Wales with increased access to REZ generation from Southern New South Wales, long duration storage in Snowy 2.0, and imports from Victoria and South Australia.

Switching Station Near Wondalga is found to be optimal at its EISD of December 2030 in the least-cost DPs for *Step Change* and *Accelerated Transition* and just beyond its actionable window in July 2033 in *Slower Growth*.

Assessing the relative market benefits of Switching Station Near Wondalga via TOOT analysis

Table 37 and **Figure 23** presents the relative market benefits of delivering the project at an actionable timing in *Step Change* compared with not building it at any time in the outlook period. Most of the $410 million of benefits identified are generator and storage capital savings as well as maintenance and fuel cost savings.

By improving access to renewable generation developed in Southern New South Wales, the project reduces the need for over 500 MW of additional wind capacity in Central and Northern New South Wales, developing instead a similar capacity

[52] AEMO has modelled the EISD of this project as December 2030 as advised by Transgrid following the Draft 2026 ISP. Since modelling was completed, AEMO has been advised of a later EISD timing of April 2031.

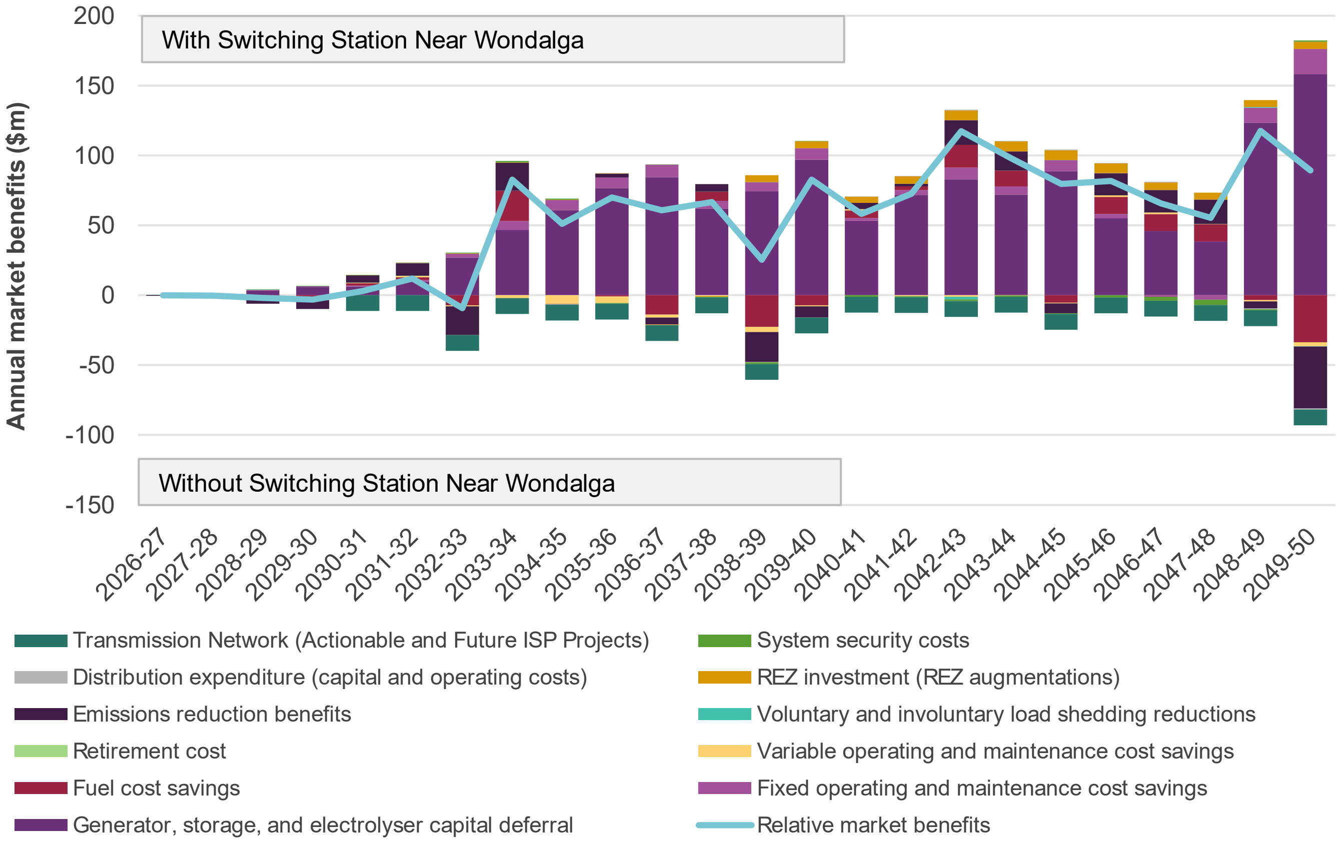
[53] 'Reported cost' refers to the estimate prepared by AEMO and reviewed by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

build of cheaper utility-scale solar in Central New South Wales. It also reduces the need to import energy from Queensland to New South Wales.

Table 37 Relative market benefits of Switching Station Near Wondalga in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	446
Fixed operating and maintenance cost savings	39
Fuel cost savings	3
Variable operating and maintenance cost savings	-10
Retirement cost	0
Voluntary and involuntary load shedding reductions	-1
Emissions reduction benefits	1
REZ investment (REZ augmentations)	19
Distribution expenditure (capital and operating costs)	0
System security costs	-2
Gross market benefits	**496**
Transmission Network (Actionable and Future ISP Projects)	-85
Total relative market benefits	**410**

Figure 23 Annual relative market benefits of Switching Station Near Wondalga in *Step Change* (2030-31)



Assessing the net market benefits of Switching Station Near Wondalga as an actionable project

The benefits of Switching Station Near Wondalga as an actionable project can be assessed through a comparison between CDP 15, where it is not at its actionable timing, and CDP 4, which features delivery of Switching Station Near Wondalga at its EISD. This comparison, in **Table 38**, shows that an actionable project would deliver an increase in weighted net market benefits of $20 million, with the benefits primarily accruing due to the more significant benefit in *Accelerated Transition*.

Table 38 Comparing net market benefits between CDP 4 and CDP 15 ($ billion) – Switching Station Near Wondalga

	CDP 4 – with actionable Switching Station Near Wondalga	CDP 15 – without actionable Switching Station Near Wondalga	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.30	0.02
Step Change	29.55	29.52	-0.02
Accelerated Transition	42.55	42.50	-0.05
Weighted net market benefits	27.86	27.84	-0.02
Ranking based on weighted net market benefits	1	4	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

While delivering the project at an actionable timing would yield a reduction in benefits in *Slower Growth*, the overall increase in weighted net market benefits is driven by a $50 million reduction in cost associated with delivering Switching Station Near Wondalga at actionable timing in *Accelerated Transition*. This is due to additional capital expenditure incurred by needing to develop additional utility-scale storage and utility-scale solar capacity across New South Wales and Queensland when the project is deferred, as well as small increases in fuel cost from additional coal and gas generation.

Assessing the regrets associated with not treating Switching Station Near Wondalga as an actionable project

Table 39 shows the change in regrets associated with delivering Switching Station Near Wondalga to a non-actionable timing. While there is an increase in regret associated with under-investment in *Step Change* and *Accelerated Transition*, the worst weighted regrets in both CDP 4 and CDP 15, despite marginally decreasing, are still coming from the outcomes in *Slower Growth*. This therefore leads to worst weighted regret reducing slightly (by just $5 million) when the project has a non-actionable delivery.

Table 39 Weighted and worst weighted regrets of CDP 4 and CDP 15 ($ million) – Switching Station Near Wondalga

	CDP 4 – with actionable Switching Station Near Wondalga	CDP 15 – without actionable Switching Station Near Wondalga	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	135	-5
Step Change	101	111	10
Accelerated Transition	43	57	14
Worst weighted regrets	140	135	-5
Ranking based on worst weighted regrets	5	1	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Victoria – New South Wales Interconnector West (VNI West)

	South West NSW REZ (N5 Option 1, N5 Option 2) Stage 1 and Victoria – New South Wales (Bulgana – Kerang – Dinawan) Stage 2
EISD	November 2031
Actionable window length	8 years (actionable in 2020, 2022 and 2024 ISPs)
Reported cost[54]	$7,600 million[55,56] Class 4 (-30%/+50%)
Cost adjusted for transmission cost escalation	$7,886 million (*Slower Growth*, 2031-32) $7,750 million (*Step Change*, 2031-32) $7,830 million (*Accelerated Transition*, 2031-32)
Flow path or REZ	West and North Victoria to Southern New South Wales
Capacity increase	1,890 MW forward/1,670 MW reverse

VNI West is a series of transmission builds and upgrades that would provide benefits to support the transition of Victoria's energy supply from brown coal to a renewable energy portfolio mix of utility-scale solar, onshore, and offshore wind, while increasing access to Snowy 2.0 and other supply from the north, as well as enabling efficient sharing of surplus renewable energy to northern regions. It also would mitigate the risk to reliable energy supply of earlier than expected coal plant closures in Victoria and New South Wales.

As VNI West was identified as an actionable project in the last three ISPs, it has an actionable window of eight years from its EISD (being 2031-32). This augmentation between Victoria and New South Wales provides a transfer capacity increase of 1,890 MW towards New South Wales and 1,670 MW towards Victoria at a cost of $7,750 million[57] in 2031-32 in *Step Change*. It also provides efficient access to North West Victoria and South West New South Wales REZs. It has been identified as optimal if delivered at an actionable timing in the least-cost DP for all three scenarios.

Assessing the relative market benefits of Victoria – New South Wales Interconnector West (VNI West) via TOOT analysis

Table 40 highlights the relative market benefits of an actionable VNI West delivered at its EISD provides, relative to it never being developed. These benefits result mainly from generator and storage capital and maintenance deferral and fuel costs savings to a lesser extent. Overall, VNI West contributes approximately $647 million in relative market benefits – with savings compounding further into the outlook period, as demonstrated by **Figure 24**. This is despite a nearly doubling of capital costs since the 2024 ISP.

Without VNI West, around 3 GW of additional wind capacity is required to be built in the NEM in the 2030s, mostly in New South Wales, instead of 2 GW of utility-scale solar capacity in Victoria that can help meet energy demand in New South

[54] 'Reported cost' refers to the estimate provided by the TNSPs. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[55] AEMO has reported the total project cost. Transgrid has advised $565 million of this amount relates to approved early works and other incurred costs that should be excluded from the cost estimate for the 2026 ISP in accordance with the AER's CBA Guidelines. AEMO has therefore excluded these costs from the ISP assessment.

[56] A third Dinawan transformer (N5 Option 2) has been added to the South West NSW REZ scope to expand the REZ transfer capacity from Dinawan by 1,800 MW. This has been modelled separately at an additional cost of $116 million Class 5b (±50%), above the $7,600 million cost of VNI West, which includes two transformers only.

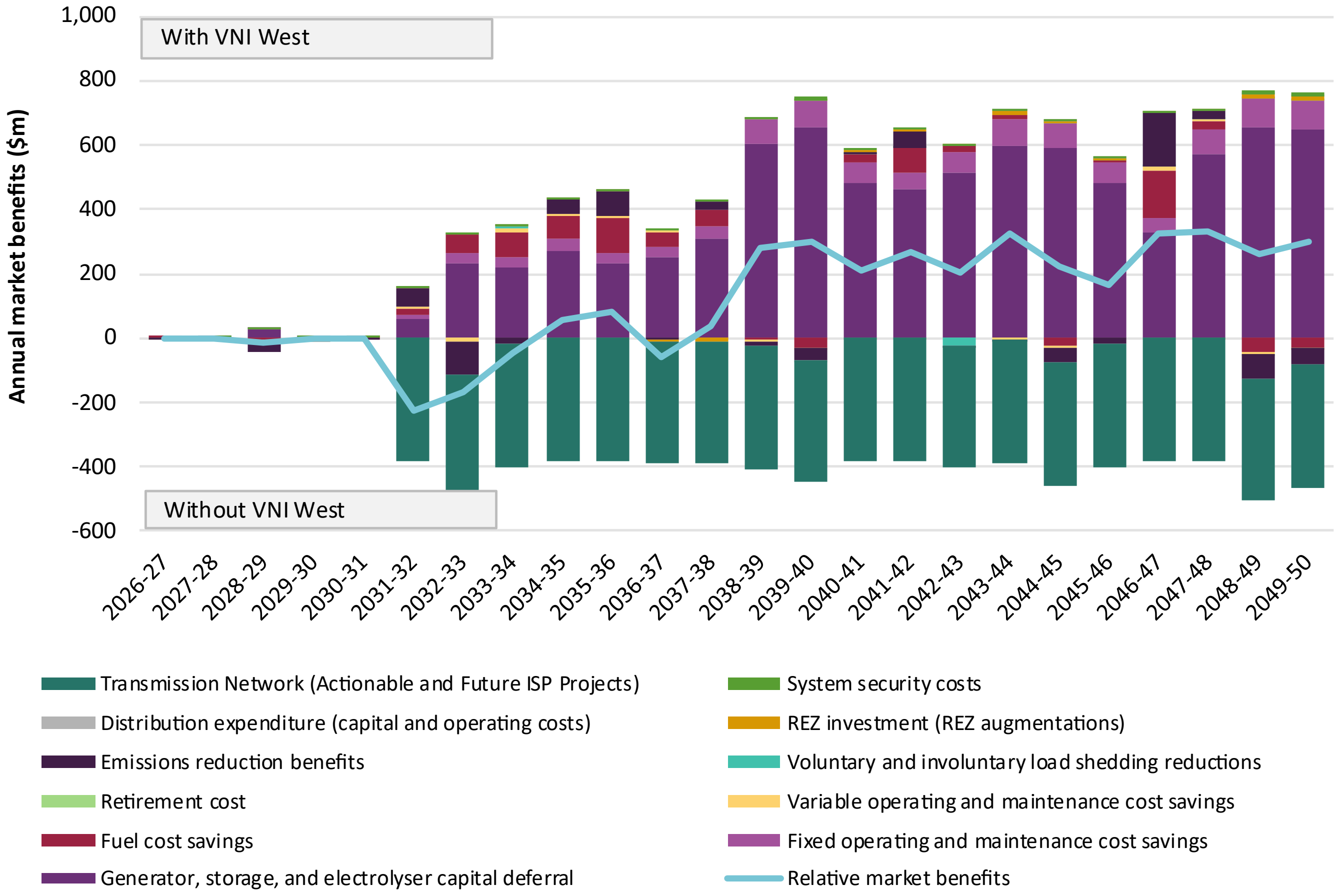
[57] This cost has nearly doubled since the 2024 ISP and is exclusive of the $565 million that Transgrid has advised AEMO relates to approved early works and other incurred costs. These already incurred costs have been excluded from the 2026 ISP CBA in accordance with the AER's CBA Guidelines.

Wales with VNI West delivered. If VNI West is not delivered there is also a greater reliance on gas-powered generation to meet peak demand in Greater Melbourne and Geelong as opposed to utilising battery storage and pumped hydro. The greater interconnection of the grid that VNI West provides leads to significant energy production efficiency improvements for the entire NEM.

Table 40 Relative market benefits of VNI West in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	2,619
Fixed operating and maintenance cost savings	337
Fuel cost savings	270
Variable operating and maintenance cost savings	2
Retirement cost	-0
Voluntary and involuntary load shedding reductions	-3
Emissions reduction benefits	3
REZ investment (REZ augmentations)	11
Distribution expenditure (capital and operating costs)	2
System security costs	33
Gross market benefits	**3,274**
Transmission Network (Actionable and Future ISP Projects)	-2,627
Total relative market benefits	**647**

Figure 24 Annual relative market benefits of VNI West in *Step Change* (2031-32)



Assessing the net market benefits of Victoria – New South Wales Interconnector West (VNI West) as an actionable project

The benefits of VNI West as an actionable project can be assessed by comparing CDP 4 with CDP 16 (which features a delay to VNI West delivery to 2039-40 – outside its actionable window). As **Table 41** shows, delivering VNI West at its actionable timing provides $360 million more in weighted net market benefits. In the least-cost DPs in all scenarios, development of VNI West is found to be optimal at its EISD.

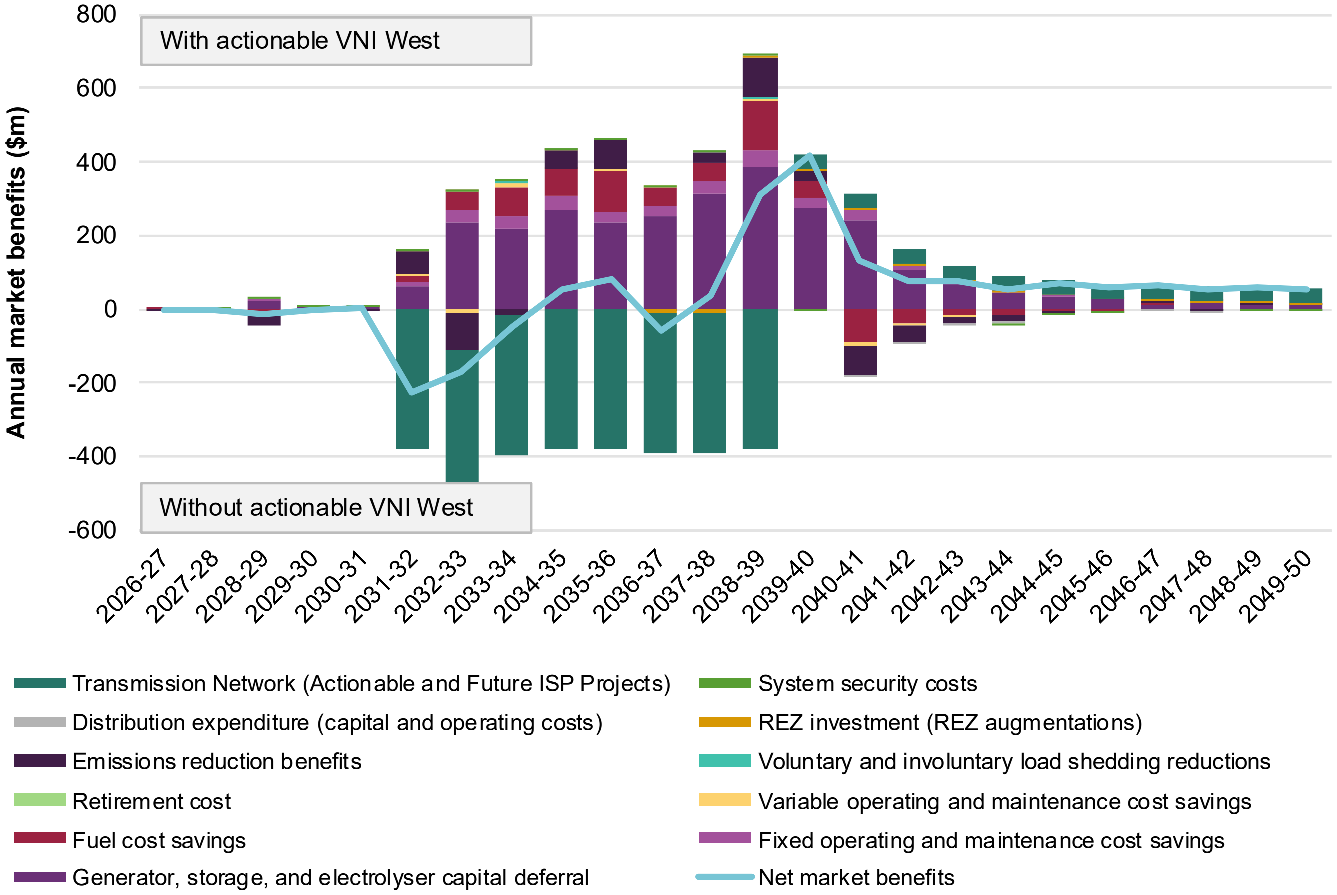
Table 41 Comparing net market benefits between CDP 4 and CDP 16 ($ billion) – VNI West

	CDP 4 – with actionable VNI West	CDP 16 – without actionable VNI West	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.28	-0.01
Step Change	29.55	29.31	-0.23
Accelerated Transition	42.55	41.64	-0.91
Weighted net market benefits	27.86	27.50	-0.36
Ranking based on weighted net market benefits	1	22	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change*, delaying the delivery of VNI West to outside the actionable window results in an increase in generation and fuel costs over the period of the delay. Victorian offshore wind and Tasmanian hydro generation, which would otherwise be used to help service load in New South Wales and Queensland, is more often curtailed due to constrained network capacity. To make up for this curtailed energy generation, development of an additional 2 GW of wind capacity in Central New South Wales (700 MW), Northern New South Wales (650 MW) and Northern South Australia is brought forward. Moreover, a significant reduction in curtailment of utility-scale solar and wind capacity in New South Wales, expected in the short-term outlook under the New South Wales Energy Roadmap, is delayed until the project is delivered. This includes capacity associated with augmentation of the South West New South Wales REZ delivered alongside VNI West. The annual net market benefits of delivering VNI West at an actionable timing, rather than in 2039-40, are illustrated in **Figure 25**.

Figure 25 Annual net market benefits associated with an actionable VNI West, *Step Change*



Under *Slower Growth*, an additional 2 GW of utility-scale solar and wind generation capacity is brought forward in Queensland to support regional supply if VNI West is not delivered at an actionable timing. However, due to the reduced export capability from Victoria and Tasmania into the northern states, approximately 1 TWh per annum of additional black coal generation is required from 2032-33 to 2035-36 to maintain supply. This limitation is primarily driven by severe constraints on the interconnector between Victoria and New South Wales which would persist until the development of VNI West.

In *Accelerated Transition*, the development of an actionable VNI West allows for greater flows from wind and deep storage in Southern New South Wales into Victoria, displacing the usage of gas-powered generation and delaying the build of 2.5 GW of utility-scale solar and wind.

Under all scenarios, VNI West enables greater transfer capability and system flexibility, which supports the accelerated integration of renewable generation and improves overall network resilience.

Delivery pathways for the portion of VNI West that provides access to South West REZ on the New South Wales side is now aligned to the New South Wales framework, opening the possibility of sequenced delivery of this project. Consistent with testing undertaken for the Draft 2026 ISP, the ISP analysis reconfirmed the relative efficiency of delivering VNI West as a single integrated project rather than staging the South West NSW REZ component ahead of the interconnector upgrade.

Assessing the regrets associated with not treating Victoria – New South Wales Interconnector West (VNI West) as an actionable project

As **Table 42** shows, delaying the delivery of VNI West until after its actionable window increases regrets across all scenarios and results in an increase in worst weighted regrets by $149 million, which comes from the under-investment in transmission in *Accelerated Transition*.

Table 42 Weighted and worst weighted regrets of CDP 4 and CDP 16 ($ million) – VNI West

	CDP 4 – with actionable VNI West	CDP 16 – without actionable VNI West	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	143	2
Step Change	101	208	107
Accelerated Transition	43	289	246
Worst weighted regrets	140	289	149
Ranking based on worst weighted regrets	5	16	NA

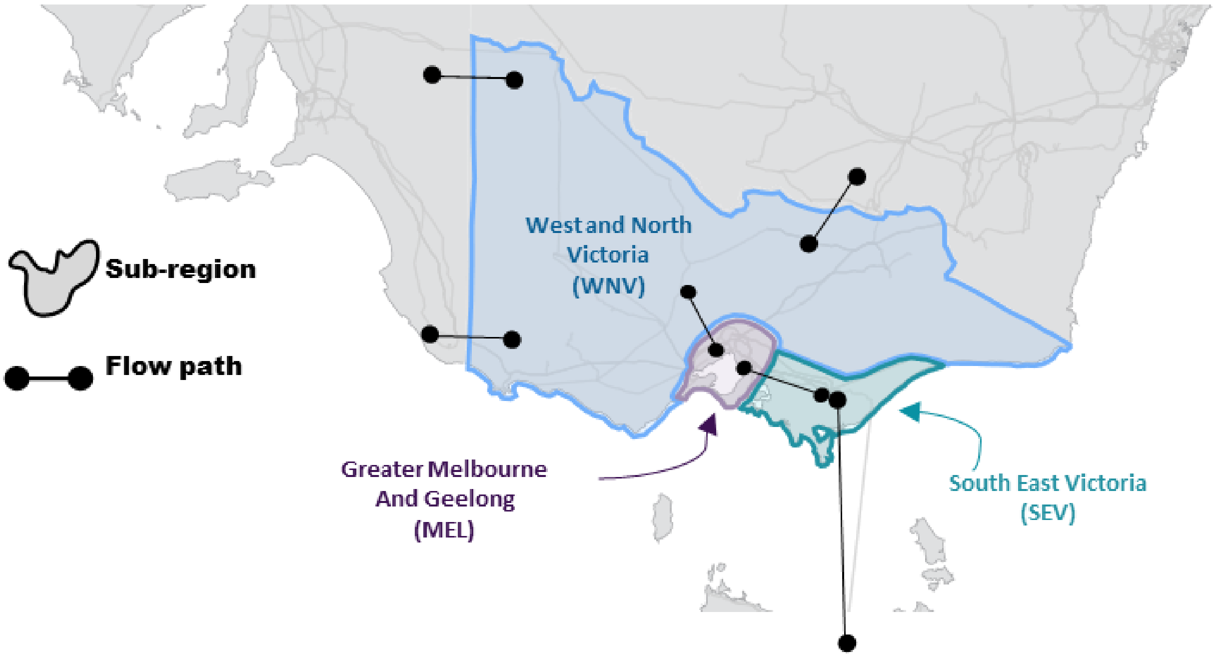
A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Western Victoria Reinforcement program

	MEL-WNV Option 1
EISD	June 2029
Actionable window length	2 years (not previously actionable)
Reported cost[58]	$128 million[59],[60] Class 5b (±50%)
Cost adjusted for transmission cost escalation	$130 million (*Slower Growth*, 2028-29) $130 million (*Step Change*, 2028-29) $132 million (*Accelerated Transition*, 2028-29)
Flow path or REZ	Greater Melbourne and Geelong to West and North Victoria
Capacity increase	800 MW reverse

In the 2024 ISP, a future ISP project in the western side of Melbourne was identified. For the 2026 ISP, recognising the lack of spatial granularity in Victoria and central South Australia, the ISP capacity outlook model representation of both regions was increased, splitting Victoria into three sub-regions and enabling greater analysis of flows between the Greater Melbourne and Geelong sub-region and West and North Victoria sub-region. **Figure 26** below shows this flow path in a map.

Figure 26 Sub-regional representation of Victoria



58 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

59 This is the 2024 cost of Option 1B of the Western Metropolitan Melbourne Reinforcement project presented in the PSCR.

60 The estimated cost includes only the incremental cost of upgrading the Keilor transformers to 1000 MVA. Costs for the replacement of the transformers are expected to be covered by the asset replacement RIT-T that is nearing completion. Further information is at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nsp_consultations/2025/kts-a-transformer-replacement-padr-final.pdf?la=en.

Western Victoria Reinforcement program is an upgrade of the Geelong, Keilor and Deer Park transmission lines to improve their flow capacity from West and North Victoria sub-region to Greater Melbourne and Geelong sub-region, enable the renewable energy developed in West and North Victoria sub-region, and support reliability of supply to Greater Melbourne and Geelong sub-region.

The project considered for this ISP would increase the transfer capacity into Greater Melbourne and Geelong by 800 MW, at a cost of $130 million if delivered at EISD of 2028-29 in *Step Change*. As this project has not been declared as actionable in any previous ISP, it has a two-year actionable window. The optimal timing of Western Victoria Reinforcement program is found to be at EISD in the least-cost DPs for *Step Change* and *Accelerated Transition*, and 2039-40 for *Slower Growth*.

A larger option, South West Victoria expansion program, which would include new transmission lines and substations in Western Victoria, requires earlier development of the smaller option. South West Victoria expansion program provides an additional 2,000 MW of capacity at a cost of $1,496 million if delivered at its EISD of 2033-34. South West Victoria expansion program is found in the least-cost DP of *Step Change* as a future project delivering benefits at a non-actionable timing, as seen in **Table 12** (in Section A6.4.5).

Assessing the relative market benefits of Western Victoria Reinforcement program via TOOT analysis

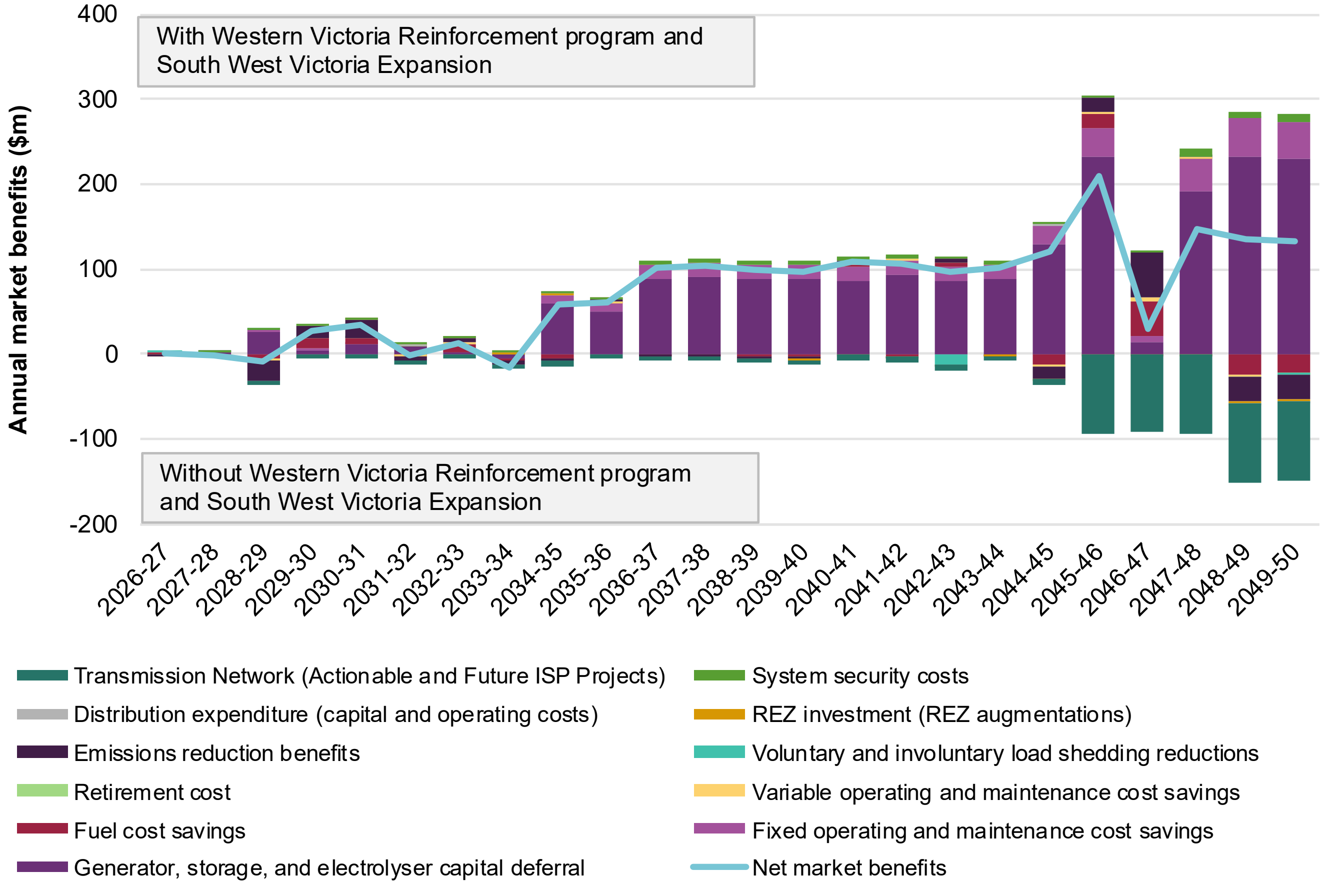
Table 43 and **Figure 27** present the relative market benefits of the Western Victoria Reinforcement program and its larger South West Victoria expansion program, compared with not delivering the projects at any time in the outlook period. Removing the Western Victoria Reinforcement program project would inhibit the development of the larger extension as well, since the Western Victoria Reinforcement program is a pre-requisite, so this TOOT removed both projects in its analysis.

The majority of the $551 million worth of relative market benefits from the delivery of the projects come from deferral of generator and storage capital cost. The benefits of the projects arise from 2029-30 but accrue more significantly from 2035-36, as the larger option avoids more significant costs.

Table 43 Relative market benefits of Western Victoria Reinforcement program and South West Victoria Expansion in *Step Change* (2028-29 and 2045-46 respectively)

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	560
Fixed operating and maintenance cost savings	103
Fuel cost savings	11
Variable operating and maintenance cost savings	4
Retirement cost	0
Voluntary and involuntary load shedding reductions	-4
Emissions reduction benefits	1
REZ investment (REZ augmentations)	0
Distribution expenditure (capital and operating costs)	2
System security costs	23
Gross market benefits	**700**
Transmission Network (Actionable and Future ISP Projects)	-149
Total relative market benefits	**551**

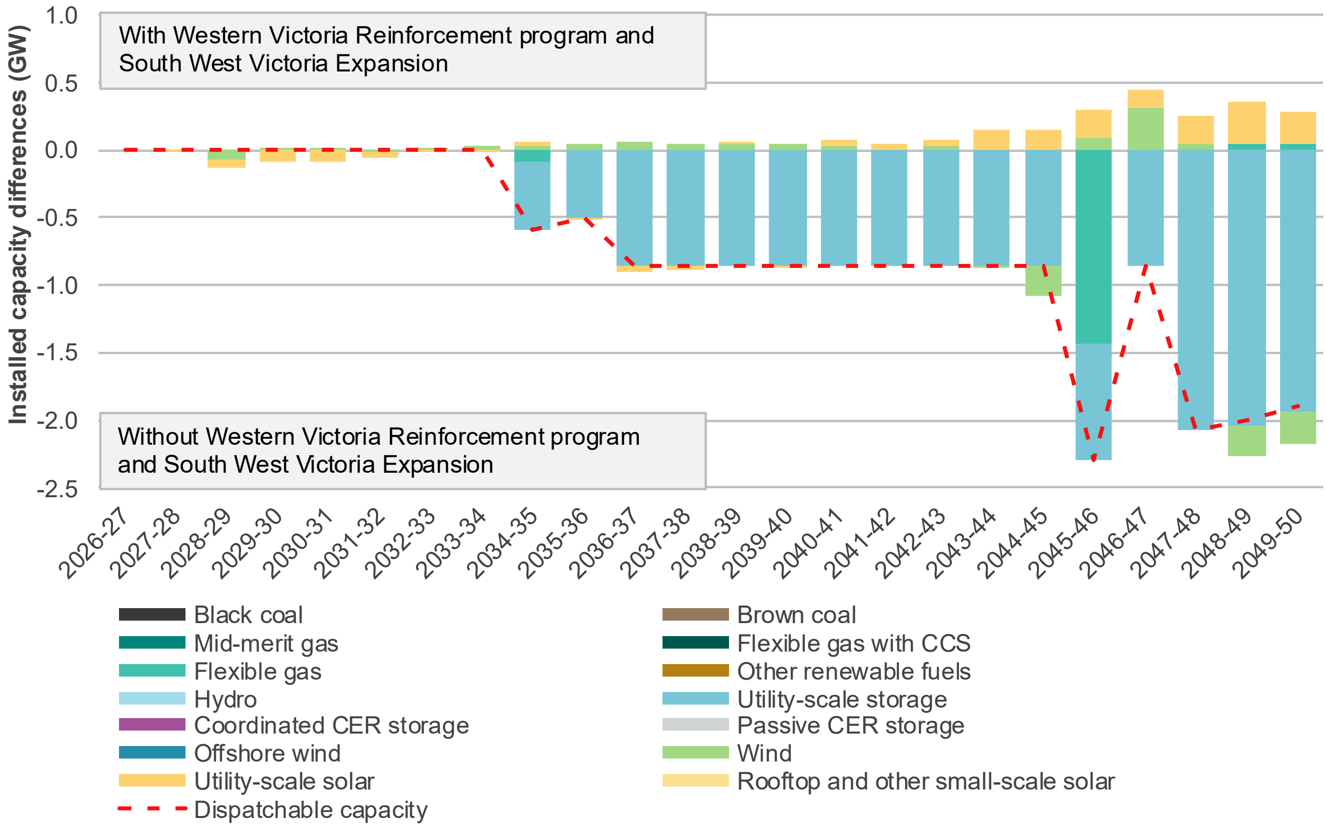
Figure 27 Annual relative market benefits of Western Victoria Reinforcement program and South West Victoria Expansion in *Step Change* (2028-29 and 2045-46 respectively)



As seen in **Figure 28**, the smaller augmentation avoids some utility-scale solar and wind capacity, but most of the benefits derived from the two options are due to avoiding the need for additional utility-scale storage in Greater Melbourne and Geelong sub-region from 2034-35. These benefits arise mostly from the development of South West Victoria Expansion.

The projects allow more efficient sharing of firming capacity in Victoria by allowing Greater Melbourne and Geelong to access dispatchable capacity in West and North Victoria. Without the augmentations, there is a surplus of firm capacity in West and North Victoria sub-region that cannot be fully utilised when required; this leads to additional firming capacity to be built in Greater Melbourne and Geelong.

Figure 28 Comparison of capacity with and without Western Victoria Reinforcement program and South West Victoria Expansion in *Step Change* (2028-29 and 2045-46 respectively)



Assessing the net market benefits of Western Victoria Reinforcement program as an actionable project

CDP 4 has delivery of the Western Victoria Reinforcement program at its EISD, whereas CDP 17 features it as a non-actionable project – its delivery is delayed by two years to 2031-32 in *Step Change* and *Accelerated Transition,* and is delayed to 2039-40 in *Slower Growth*.

The benefits of an actionable Western Victoria Reinforcement program by scenario are shown in **Table 44** below. This analysis isolates the Western Victoria Reinforcement program from the later larger augmentation discussed in the previous section. The project delivers $180 million more weighted net market benefits if delivered at its EISD.

Table 44 Comparing net market benefits between CDP 4 and CDP 17 ($ billion) – Western Victoria Reinforcement program

	CDP 4 – with actionable Western Victoria Reinforcement program	CDP 17 – without actionable Western Victoria Reinforcement program	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.18	-0.11
Step Change	29.55	29.48	-0.06
Accelerated Transition	42.55	42.12	-0.43
Weighted net market benefits	27.86	27.68	-0.18
Ranking based on weighted net market benefits	1	13	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

If the project is delayed beyond its actionable window in *Step Change*, less generation flows into the Greater Melbourne and Geelong sub-region, reducing the ability of batteries in that sub-region to charge then be dispatched to serve the broader NEM, despite around 2 GW of battery capacity anticipated by 2030. As a result, renewable investment is brought forward in Tasmania and Queensland, with approximately 70 MW of additional capacity developed earlier than otherwise required. This is accompanied by increased reliance on coal generation in Queensland and New South Wales.

Similar observations apply in *Accelerated Transition* at a larger scale, with greater earlier investment in renewable energy investments, reaching 550 MW additional capacity in 2031-32 if Western Victoria Reinforcement program is delayed to after its actionable window. In addition, in *Accelerated Transition*, delaying the project would require an additional increase to VRE capacity in other regions, increasing REZ investment costs.

Relative to CDP 4, delaying the Western Victoria Reinforcement program in *Slower Growth* to 2039-40 results in additional gas generation capacity being required from 2037-38 in Greater Melbourne and Geelong and Tasmania to meet peak demand. With the project as actionable, a smaller amount of battery capacity is required in the same regions from 2041-42 resulting in reduced capital expenditure, fuel and emission costs.

Assessing the regrets associated with not treating Western Victoria Reinforcement program as an actionable project

Table 45 presents the weighted regrets in each of the scenarios and worst weighted regrets for CDP 4 and CDP 17, with a non-actionable timing increasing regrets in all three scenarios. Delaying the project to a non-actionable timing increases weighted regret in *Accelerated Transmission* by $117 million the most, since it is in this scenario that the project delivers the most benefits.

Table 45 Weighted and worst weighted regrets of CDP 4 and CDP 17 ($ million) – Western Victoria Reinforcement program

	CDP 4 – with actionable Western Victoria Reinforcement program	CDP 17 – without actionable Western Victoria Reinforcement program	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	169	28
Step Change	101	130	30
Accelerated Transition	43	160	117
Worst weighted regrets	140	169	28
Ranking based on worst weighted regrets	5	11	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Gippsland Offshore Wind Transmission

	Stage 1 [V8 Option 1]	Stage 2 – Phase 1 [V8 Option 2]	Stage 2 – Phase 2 [South East Victoria group constraint (SEVIC1) Option 1]
EISD	July 2031	July 2033	July 2038
Actionable window length	2 years (not previously actionable)	2 years (not previously actionable)	2 years (not previously actionable)
Reported cost[61]	$1,500 million[62] Class 5 (+100%/-50%)	$790 million Class 5 (+100%/-50%)	$400 million Class 5 (+100%/-50%)
Cost adjusted for transmission cost escalation	$1,646 million (*Slower Growth*, 2031-32) $1,653 million (*Step Change*, 2031-32) $1,690 million (*Accelerated Transition*, 2031-32)	$892 million (*Slower Growth*, 2033-34) $901 million (*Step Change*, 2033-34) $925 million (*Accelerated Transition*, 2033-34)	$494 million (*Slower Growth*, 2038-39) $502 million (*Step Change*, 2038-39) $522 million (*Accelerated Transition*, 2038-39)
Flow path or REZ	Gippsland Offshore REZ	Gippsland Offshore REZ and South-East Victoria group constraint[A]	Gippsland Offshore REZ and South-East Victoria group constraint[A]
Capacity increase	2,000 MW	2,000 MW (Gippsland Offshore REZ) and 2,000 MW (South-East Victoria group constraint[A], SEVIC1)	3,000 MW (Gippsland Offshore REZ) and 4,600 MW (South-East Victoria group constraint[A], SEVIC1)

A. The South-East Victoria group constraint also services the TAS-SEV flow path, Loy Yang and Valley Power, hence the capacity increases quoted are not additive.

The Gippsland Offshore REZ was declared by the Federal Minister for Climate and Energy as suitable for offshore renewable energy in December 2022[63]. The REZ has relatively shallow waters and strong wind resources, with a connection point close to existing 500 kV networks at Loy Yang (for Stage 1) and Hazelwood (for Stage 2 – Phase 1). Establishing a transmission connection point would allow a connection of offshore wind capacity to meet the Victorian Offshore Wind Target of 9 GW by 2039-40. This would provide bulk generation with higher capacity factors and greater forecast contribution to meeting peak demand than most other renewable generation alternatives.

The last stage of the Gippsland Offshore Wind Transmission project includes a new terminal station that further increases the transmission capacity through South East Victoria, in Victoria's Gippsland region, by 4.6 GW to harness renewable generation from offshore wind and Tasmania through Project Marinus. If built, it would be expected to reduce the levels of curtailment of the renewable generation in these locations significantly, which improves the supply of generation into the Greater Melbourne and Geelong load centres, and the rest of the NEM.

The project is proposed to be delivered in three stages, with the development of each stage appropriately related to the timing of offshore wind development in Victoria, increasing transfer capacities as outlined in the table above.

None of these stages had been declared actionable in previous ISPs, therefore all have an actionable window of two years. All three stages are found to be optimal if delivered at their EISDs in the least-cost DPs for *Step Change* and *Accelerated Transition*, while only the third stage (Stage 2 – Phase 2) is optimal at its EISD in *Slower Growth*, with the first two stages (Stage 1 and Stage 2 – Phase 1) being preferred just outside their actionable windows.

Although Stage 1 and Stage 2 – Phase 1 are a pre-requisite for Stage 2 – Phase 2, it is plausible to deliver Stage 1 and Stage 2 – Phase 1 at a non-actionable timing without impacting the earliest timing of Stage 2 – Phase 2. As such, this section first

61 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

62 As advised by VicGrid, AEMO has used the upper bound of the range for the purposes of use in the ISP modelling.

63 At https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/gippsland.

discusses the relative net market benefits of all three projects via TOOT analysis, followed by the merits of identifying each project as actionable in isolation.

Assessing the relative market benefits of Gippsland Offshore Wind Transmission (Stage 1, Stage 2 – Phase 1, and Stage 2 – Phase 2) via TOOT analysis

Table 46 highlights the relative market benefits that the Gippsland Offshore Wind Transmission project provides when delivered at actionable timing compared with not delivering the projects at any time in the outlook period. Because the Victorian offshore wind is dependent on some or all of these transmission projects to transmit generation to the grid, this TOOT analysis is effectively assuming little Victorian offshore wind contribution in the NEM.

As the Australian Energy Commission (AEMC) Targets Statement[64] includes the Victorian Offshore Wind Target, this analysis assumes this target is met according to the schedule shown in **Figure 29**, even in development paths where the transmission projects are not delivered. Without the transmission developments, generation from the Gippsland Offshore REZ would be totally curtailed, and while offshore wind developments could shift to the Southern Ocean REZ, these also would be highly curtailed from network limits affecting South Eastern Victoria without augmentation.

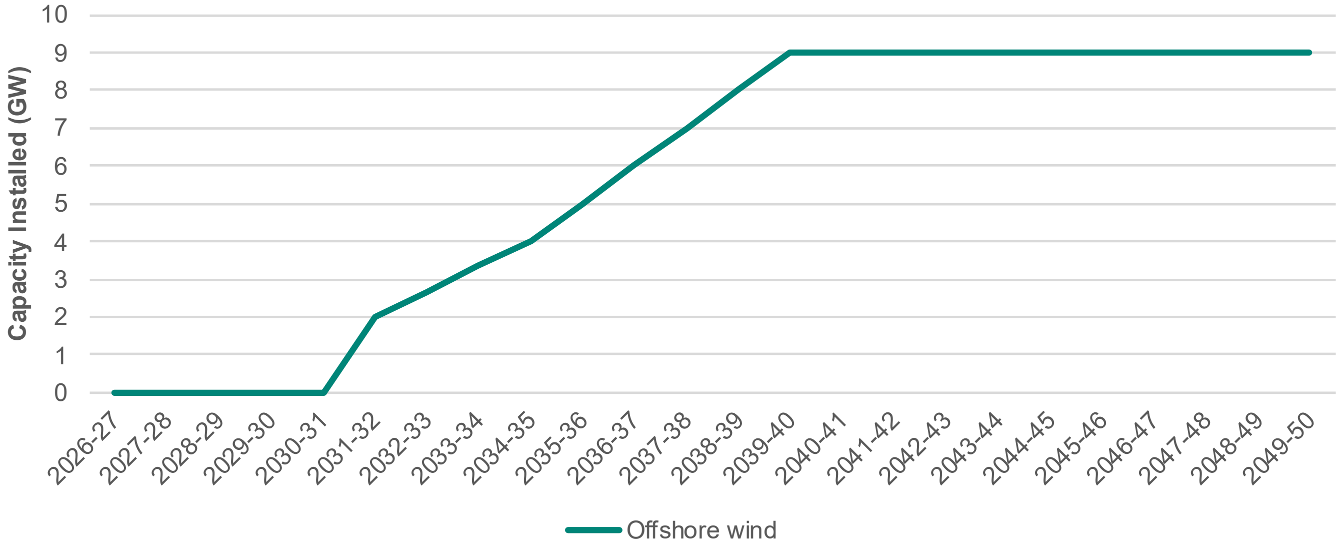
While the relative market benefit in the TOOT analysis is significant, at $11 billion, care should be taken in interpreting this, as the capital cost of offshore wind development is not assumed to be avoided in the event that the Gippsland Offshore Wind Transmission project is not delivered, for the reasons outlined above. Without transmission to bring Victorian offshore wind to market, more onshore generator and storage capital expenditure is required, accompanied by higher maintenance costs and fuel costs over the outlook period.

Table 46 Relative market benefits of Gippsland Offshore Wind Transmission (Stage 1, Stage 2 – Phase 1, and Stage 2 – Phase 2) in Step Change (at 2031-32, 2033-34, and 2038-39, respectively)

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	9,155
Fixed operating and maintenance cost savings	1,746
Fuel cost savings	385
Variable operating and maintenance cost savings	66
Retirement cost	0
Voluntary and involuntary load shedding reductions	-3
Emissions reduction benefits	5
REZ investment (REZ augmentations)	299
Distribution expenditure (capital and operating costs)	19
System security costs	234
Gross market benefits	**11,907**
Transmission Network (Actionable and Future ISP Projects)	-888
Total relative market benefits	**11,019**

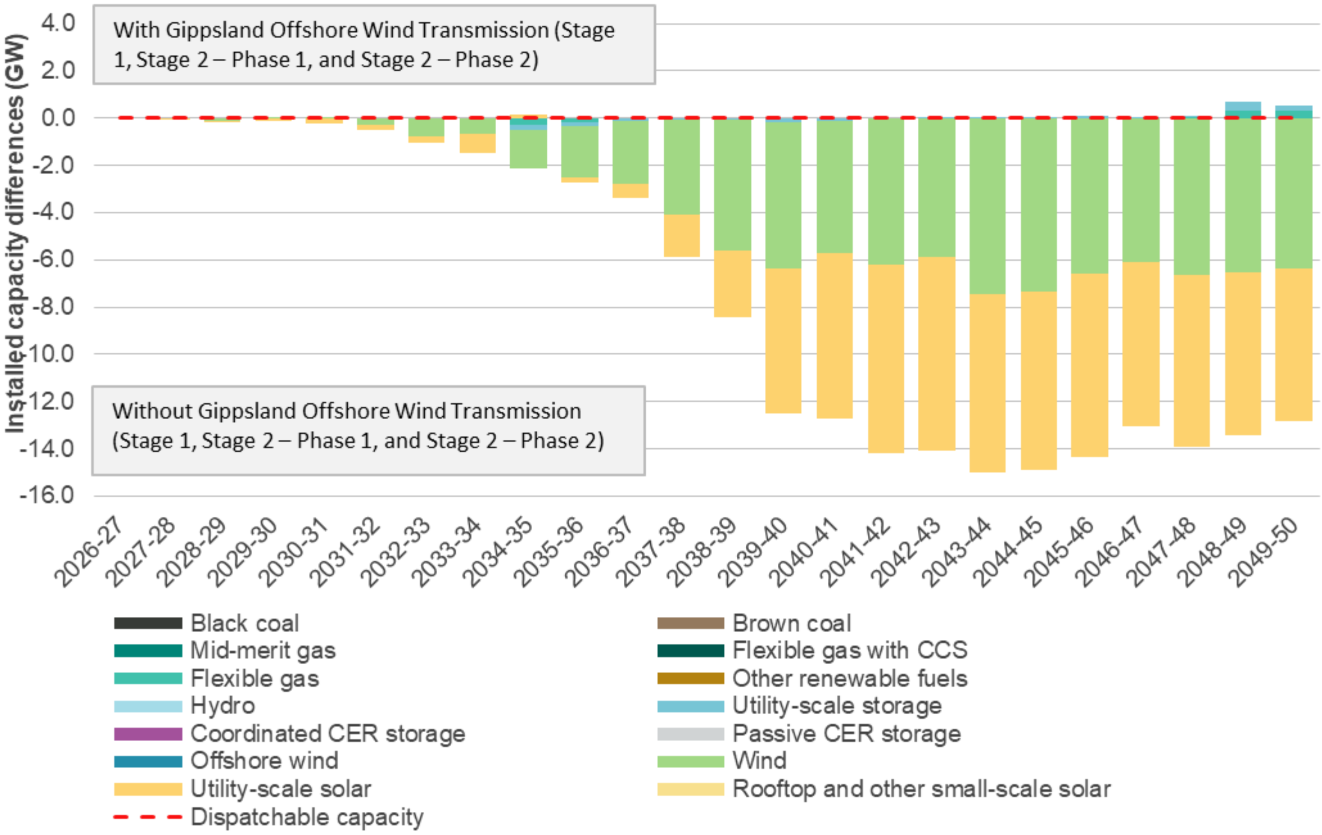
[64] AEMC (2025), Emissions targets statement under the national energy laws, https://www.aemc.gov.au/sites/default/files/2025-04/Emissions%20targets%20statement%20-%20April%202025%20version.pdf.

Figure 29 Assumed Victorian offshore wind development to meet Victorian Offshore Wind Target



As shown below in **Figure 30**, delivery of projects avoids alternative developments of almost 15 GW of utility-scale solar and wind across the outlook period which would otherwise need to be built to meet forecast energy consumption growth and to meet the Victorian Renewable Energy Target, saving significant capital investment. By 2050, an additional 6 GW of utility-scale VRE would be required in Victoria to offset this absent generation, along with an additional 4 GW in New South Wales, 2 GW in South Australia and 1 GW in Tasmania. Greater use of the Southern Ocean REZ, which does have an existing connection to the grid without transmission build, is also required.

Figure 30 Comparison of capacity with and without Gippsland Offshore Wind Transmission (Stage 1, Stage 2 – Phase 1, and Stage 2 – Phase 2) in *Step Change* (at 2031-32, 2033-34, and 2038-39, respectively)



Note: Offshore wind development occurs to meet the offshore wind target regardless of whether the transmission is built but is curtailed significantly without the development of the Gippsland Offshore Wind Transmission project.

Assessing the net market benefits of Gippsland Offshore Wind Transmission Stage 1 as an actionable project

CDP 4 delivers both earlier stages of the Gippsland Offshore Wind Transmission Stage 1 at their respective EISDs. CDP 20 features delaying Stage 1 of the project to the first year outside of its actionable window (2033-34 for Stage 1). The benefits of this project being actionable by scenario are shown in **Table 47** below.

Table 47 Comparing net market benefits between CDP 4 and CDP 20 ($ billion) – Gippsland Offshore Wind Transmission Stage 1

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 1	CDP 20 – without actionable Gippsland Offshore Wind Transmission Stage 1	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.37	0.08
Step Change	29.55	28.55	-1.00
Accelerated Transition	42.55	41.54	-1.01
Weighted net market benefits	27.86	27.14	-0.71
Ranking based on weighted net market benefits	1	27	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Delivering Gippsland Offshore Wind Transmission Stage 1 at its actionable timing provides $710 million more in weighted net market benefits than delivering it two years later, with net market benefits demonstrated in *Step Change* and *Accelerated Transition*. In both scenarios, these benefits come from deferring alternative renewable energy developments.

In *Step Change*, delivering the project at an actionable timing also avoids flexible gas and utility-scale storage capacity from 2034-35 in Greater Melbourne and Geelong, and Tasmania. In *Slower Growth*, delivering the project at an actionable timing does not result in any VRE or utility-scale storage capacity being avoided; instead, existing onshore wind and solar curtailment increases due to supply being surplus to requirements in this scenario.

It should be noted that across all scenarios, AEMO assumed that Victorian offshore wind is developed according to the schedule shown in **Figure 29**. Significant delays in the development of offshore wind capacities would impact the benefits of these associated transmission projects. In general, the development of Gippsland Offshore Wind Transmission should coincide with the build out and scaling up of offshore wind resources in that REZ.

Assessing the regrets associated with not treating Gippsland Offshore Wind Transmission Stage 1 as actionable projects

As **Table 48** shows, delaying Gippsland Offshore Wind Transmission Stage 1 until after the actionable window increases regrets in *Step Change* and *Accelerated Transition*, and in particular in *Step Change*, which consequently results in an increase in worst weighted regrets by $421 million. In *Slower Growth,* delaying the project to a non-actionable timing reduces regrets, as it avoids curtailment over the actionable window. The worst weighted regret is driven by not being able to fully utilise Victorian offshore wind generation in *Step Change* and building more onshore generation and storage to compensate.

Table 48 Weighted and worst weighted regrets of CDP 4 and CDP 20 ($ million) – Gippsland Offshore Wind Transmission Stage 1

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 1	CDP 20 – without actionable Gippsland Offshore Wind Transmission Stage 1	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	119	-22
Step Change	101	561	460
Accelerated Transition	43	316	274
Worst weighted regrets	140	561	421
Ranking based on worst weighted regrets	5	27	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the net market benefits of Gippsland Offshore Wind Transmission Stage 2 – Phase 1 as an actionable project

CDP 4 delivers both earlier stages of the Gippsland Offshore Wind Transmission Stage 1 and Stage 2 – Phase 1 at their respective EISDs. CDP 21 features delaying Stage 2 – Phase 1 of the project to the first year outside of its actionable window (2035-36). The benefits of this project being actionable by scenario are shown in **Table 49** below.

Table 49 Comparing net market benefits between CDP 4 and CDP 21 ($ billion) – Gippsland Offshore Wind Transmission Stage 2 – Phase 1

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	CDP 21 – without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.30	0.02
Step Change	29.55	29.50	-0.05
Accelerated Transition	42.55	42.51	-0.04
Weighted net market benefits	27.86	27.83	-0.03
Ranking based on weighted net market benefits	1	8	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Delivering Gippsland Offshore Wind Transmission Stage 2 – Phase 1 at its actionable timing provides $30 million more weighted net market benefits than delivering it two years later, with greater net market benefits demonstrated in *Step Change* and *Accelerated Transition*. In both scenarios, these benefits come from deferring alternative renewable energy developments. In *Step Change*, delivering the project at an actionable timing also avoids gas generation in 2033-34 and 2034-35, reducing fuel and emission costs.

In *Slower Growth*, delivering the project at an actionable timing has marginal impact as the curtailed offshore wind generation can be replaced with existing hydro and rooftop and other small-scale solar generation in this scenario, complemented by gas and coal generation. This results in increased fuel and emissions costs.

Assessing the regrets associated with not treating Gippsland Offshore Wind Transmission Stage 2 – Phase 1 as an actionable project

As **Table 50** shows, delaying Gippsland Offshore Wind Transmission Stage 2 – Phase 1 until after the actionable window increases regrets across *Step Change* and *Accelerated Transition*, however reduces regrets in *Slower Growth*. This results in a marginal decrease in worst weighted regrets by $4 million, slightly lowering the risk of over-investment in this scenario, given that the curtailed offshore wind generation can be replaced with onshore renewable energy.

Table 50 Weighted and worst weighted regrets of CDP 4 and CDP 21 ($ million) – Gippsland Offshore Wind Transmission Stage 2 – Phase 1

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 1 and Stage 2 – Phase 1	CDP 21 – without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	136	-4
Step Change	101	124	23
Accelerated Transition	43	55	12
Worst weighted regrets	140	136	-4
Ranking based on worst weighted regrets	5	2	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the net market benefits of Gippsland Offshore Wind Transmission Stage 2 – Phase 2 as an actionable project

The relative net market benefits of Gippsland Offshore Wind Transmission Stage 2 – Phase 2 can be observed by comparing CDP 4 with CDP 22, which delays the upgrade to after its actionable window in 2040-41.

As **Table 51** shows, delivering Gippsland Offshore Wind Transmission Stage 2 – Phase 2 at its actionable timing provides $230 million more in weighted net market benefits than delivering it two years later.

Table 51 Comparing net market benefits between CDP 4 and CDP 22 ($ billion) – Gippsland Offshore Wind Transmission Stage 2 – Phase 2

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	CDP 22 – without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.17	-0.11
Step Change	29.55	29.27	-0.27
Accelerated Transition	42.55	42.26	-0.29
Weighted net market benefits	27.86	27.62	-0.23
Ranking based on weighted net market benefits	1	18	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

The cost of delaying the project to beyond the actionable window in *Step Change* comes from the additional generation expenditure required to make up for the shortfall in generation that would otherwise be supplied from Victorian offshore wind. In 2039-40, offshore wind curtailment hits 29% without this project, compared with just 7% when the project is delivered at an actionable timing; and 1.4 GW of additional utility-scale solar and wind capacity is required in that year without the project at an actionable timing.

A similar dynamic affects *Accelerated Transition*, where the delay of the Gippsland Offshore Wind Transmission Stage 2 – Phase 2 constrains Victorian offshore wind generation and requires additional utility-scale solar and wind capacity to be built but on a larger scale than in *Step Change* with nearly 2.8 GW of additional capacity in 2039-40. In *Slower Growth,* a delay of this project is less impactful to the timing of other new developments.

Assessing the regrets associated with not treating Gippsland Offshore Wind Transmission Stage 2 – Phase 2 as an actionable project

Table 52 presents the impact on weighted and worst weighted regrets of delaying the project to after its actionable window. Delaying the project increases regrets (risk of under-investment in transmission) across all scenarios, but most noticeably in *Step Change*, resulting in an overall increase in worst weighted regret of $86 million.

Table 52 Weighted and worst weighted regrets of CDP 4 and CDP 22 ($ million) – Gippsland Offshore Wind Transmission Stage 2 – Phase 2

	CDP 4 – with actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	CDP 22 – without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 2	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	170	30
Step Change	101	226	125
Accelerated Transition	43	122	80
Worst weighted regrets	140	226	86
Ranking based on worst weighted regrets	5	15	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Project Marinus Stage 2

	TAS-SEV Option 2A
EISD	December 2034
Actionable window length	8 years (actionable in 2020, 2022 and 2024 ISPs)
Reported cost[65]	$2,485 million[66,67,68,69] Class 4(±30%)
Cost adjusted for transmission cost escalation	$2,432 million (*Slower Growth*, 2034-35) $2,432 million (*Step Change*, 2034-35) $2,432 million (*Accelerated Transition*, 2034-35)
Flow path or REZ	Tasmania to South East Victoria
Capacity increase	750 MW forward/750 MW reverse

Project Marinus is a two-stage augmentation with two submarine cables to improve connection to Victoria that would enable improved connection with Tasmania's high quality renewable and hydro resources. Stage 1 and Stage 2 (representing the development of the first and second cables) each provide 750 MW of transfer capacity increase between Victoria and Tasmania, with Stage 2 coming at a cost of $2,432 million in 2034-35[70]. Without Project Marinus Stage 2, additional utility-scale solar and wind capacities are required on the mainland, and Tasmania relies more heavily on hydro generation (which has a higher variable operating cost than wind and solar) to meet the Tasmanian Renewable Energy Target (TRET) in *Step Change*.

[65] 'Reported cost' refers to the estimate provided by Marinus Link Pty Ltd and TasNetworks. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[66] TAS-SEV Option 2A is a variant of Project Marinus Stage 2 (TAS-SEV Option 2) that has the Burnie-Hampshire Hills double-circuit 220 kV lines scope ($184 million) removed, as these lines are built earlier under the Tasmania REZ Expansion (T2 Option 1), which forms a separate actionable ISP project.

[67] The reported cost of $2,485 million (in $2025) represents the total cost of TAS-SEV Option 2A, escalated from the $2023 cost of $2,351 million (proponent cost $2,535 million less $184 million for Burnie-Hampshire Hills).

[68] Marinus Link Pty Ltd has advised that $51 million, in $2023, of this amount relates to approved early works and other incurred costs that should be excluded from the cost estimate for the 2026 ISP in accordance with the AER's CBA Guidelines.

[69] For this project, the reported cost is considered to already include cost escalation to the EISD.

[70] The costs presented and used in the analysis exclude the amounts related to approved early works and other incurred costs that should be excluded from the cost estimate for the 2026 ISP in accordance with the AER's CBA Guidelines. For more information, please see the 2025 *Electricity Network Options Report*.

Given the advanced state of the development of Project Marinus Stage 1, this project is classified as anticipated in the 2026 ISP and assumed to be delivered at its EISD. This section explores whether Project Marinus Stage 2 should continue to be assessed as an actionable project.

Project Marinus Stage 2 was found to be actionable in the last three ISPs which gives it an actionable window of eight years beyond its EISD. It is optimal if delivered at its EISD in the least-cost DPs for *Slower Growth* and *Accelerated Transition*, while in *Step Change* the preferred timing in the least-cost DP is 2046-47.

Assessing the relative market benefits of Project Marinus Stage 2 via TOOT analysis

Table 53 shows a reduction in relative market benefits of $105 million when delivering Project Marinus Stage 2 at its EISD in *Step Change* compared with a case without the project. The key source of gross benefits for this project is the deferral of over 1 GW of wind and utility-scale solar capacities to beyond the outlook period on the mainland. This reduces generator capital costs, maintenance costs, and REZ network capital cost that are otherwise built to accommodate new entrant renewable capacities. In addition, approximately 250 GWh per annum less flexible gas generation in the NEM is needed in the late 2030s, as Project Marinus Stage 2 enables additional generation from Tasmanian hydro and VRE to be supplied to the mainland and provide reliability of supply. This results in fuel cost savings in the late 2030s. However, in *Step Change* these cost savings over the period to 2049-50 in total do not fully offset the cost of the project if delivered at its EISD.

Table 53 Relative market benefits of Project Marinus Stage 2 in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	357
Fixed operating and maintenance cost savings	55
Fuel cost savings	67
Variable operating and maintenance cost savings	-10
Retirement cost	0
Voluntary and involuntary load shedding reductions	-3
Emissions reduction benefits	1
REZ investment (REZ augmentations)	27
Distribution expenditure (capital and operating costs)	0
System security costs	13
Gross market benefits	**505**
Transmission Network (Actionable and Future ISP Projects)	-611
Total relative market benefits	**-105**

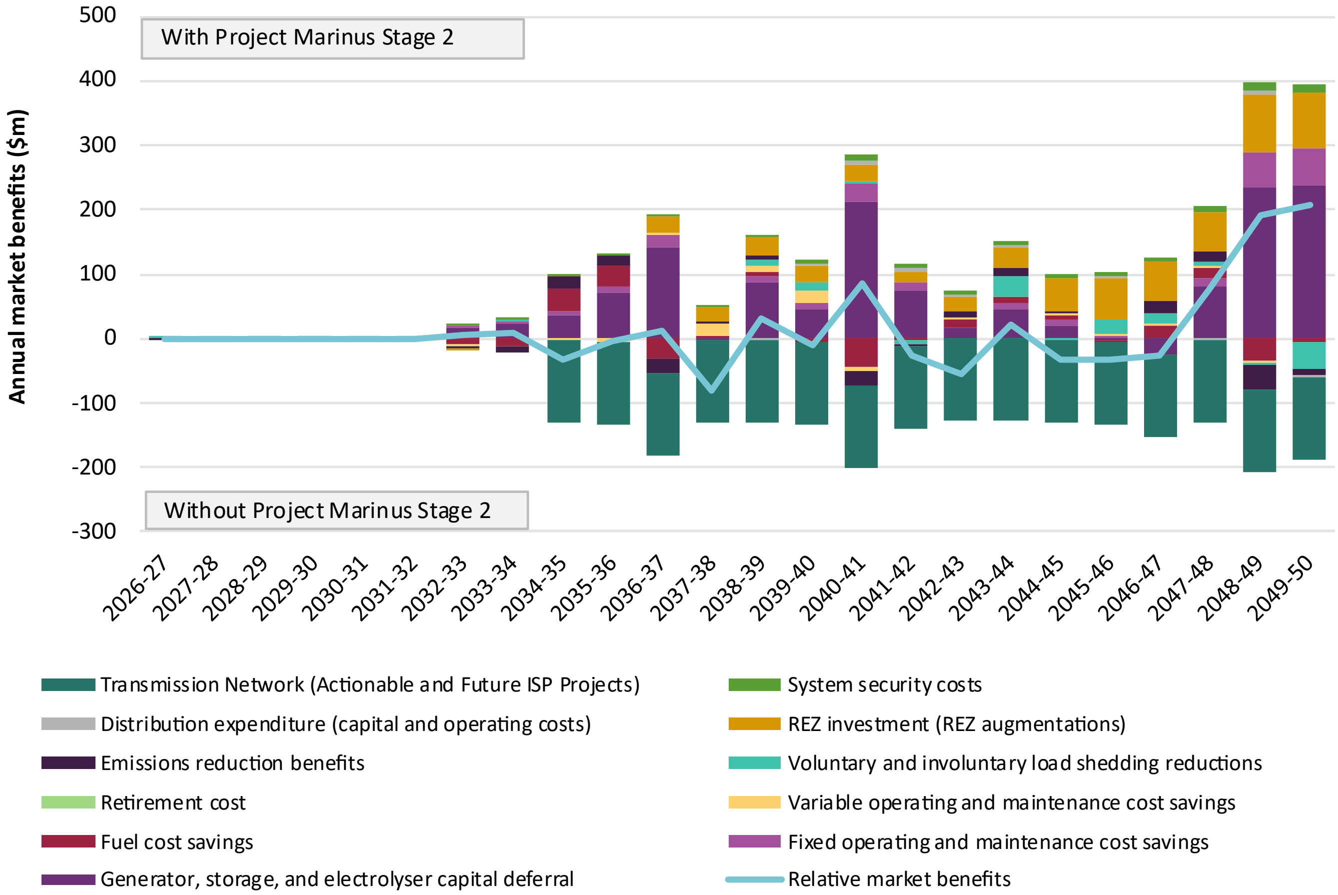
While not developing Project Marinus Stage 2 is preferable to having it at its EISD in *Step Change*, the project is shown to deliver relative market benefits of $51 million in *Accelerated Transition*, as shown in **Table 54** and **Figure 31**. The benefits are mainly derived from generator and storage capital deferral. The project avoids increasing amounts of utility-scale solar capacity from 2032-33, avoiding by 2039-40 nearly 1.25 GW of capacity in Victoria. Utility-scale solar is also avoided in other sub-regions, such as New South Wales and South Australia, particularly during the early 2030s and especially from the mid-2040s onwards. Instead, delivering Project Marinus Stage 2 allows for an additional 600 MW of wind generation to be built in Tasmania by 2039-40, and for Tasmanian VRE generation which would otherwise be curtailed to be exported to the mainland.

In summary, Project Marinus Stage 2 allows for Tasmanian surplus generation in *Slower Growth* to be exported to the mainland, while it allows for more economic sharing of resources between the mainland and Tasmania in *Accelerated Transition*. In *Step Change*, generation in Tasmania is just sufficient to meet local energy consumption and state energy policy, such that there is lesser need to increase inter-regional transfer capacity.

Table 54 Relative market benefits of Project Marinus Stage 2 in *Accelerated Transition*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	407
Fixed operating and maintenance cost savings	72
Fuel cost savings	3
Variable operating and maintenance cost savings	17
Retirement cost	-0
Voluntary and involuntary load shedding reductions	15
Emissions reduction benefits	0
REZ investment (REZ augmentations)	161
Distribution expenditure (capital and operating costs)	5
System security costs	30
Gross market benefits	**709**
Transmission Network (Actionable and Future ISP Projects)	-658
Total relative market benefits	**51**

Figure 31 Annual relative market benefits of Project Marinus Stage 2 in *Accelerated Transition* (2034-35)



Assessing the net market benefits of Project Marinus Stage 2 as an actionable project

CDP 4 has delivery of Project Marinus Stage 2 at its EISD, whereas CDP 24 in *Step Change* features delivery of the project in 2046-47 after Stage 2's actionable window (2041-42). The benefits of an actionable Project Marinus Stage 2 by scenario are displayed in **Table 55** below.

Table 55 Comparing net market benefits between CDP 4 and CDP 24 ($ billion) – Project Marinus Stage 2

	CDP 4 – with actionable Project Marinus Stage 2	CDP 24 – without actionable Project Marinus Stage 2	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	9.28	-1.00
Step Change	29.55	29.66	0.11
Accelerated Transition	42.55	42.49	-0.06
Weighted net market benefits	27.86	27.62	-0.24
Ranking based on weighted net market benefits	1	19	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

An actionable Project Marinus Stage 2 delivers significant market benefits in *Slower Growth* ($1 billion), and more marginal market benefits in *Accelerated Transition* ($62 million) scenarios, while in *Step Change*, delaying the project results in higher net market benefits. On a weighted net market benefits basis, an actionable Project Marinus Stage 2 results in $240 million more weighted net market benefit, dominated by the net market benefits in *Slower Growth*. This contrast is demonstrated by observing the annualised net benefits of the project being developed as actionable, versus delayed to after its actionable window, in *Slower Growth*, *Step Change* and *Accelerated Transition* in **Figure 32**, **Figure 33** and **Figure 34,** respectively.

Figure 32 Net market benefits of actionable Project Marinus Stage 2 in *Slower Growth*

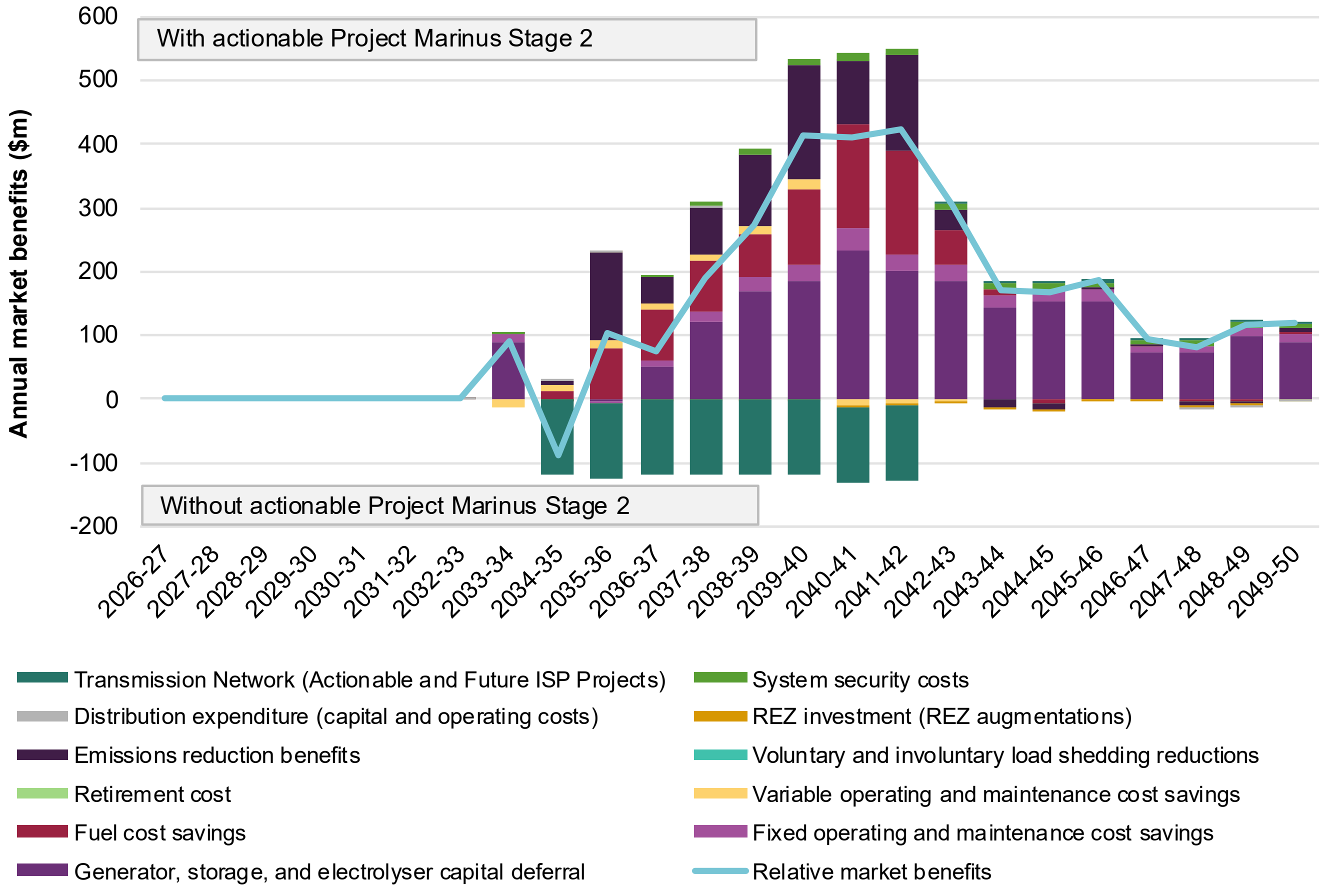


Figure 33 Net market benefits of actionable Project Marinus Stage 2 in *Step Change*

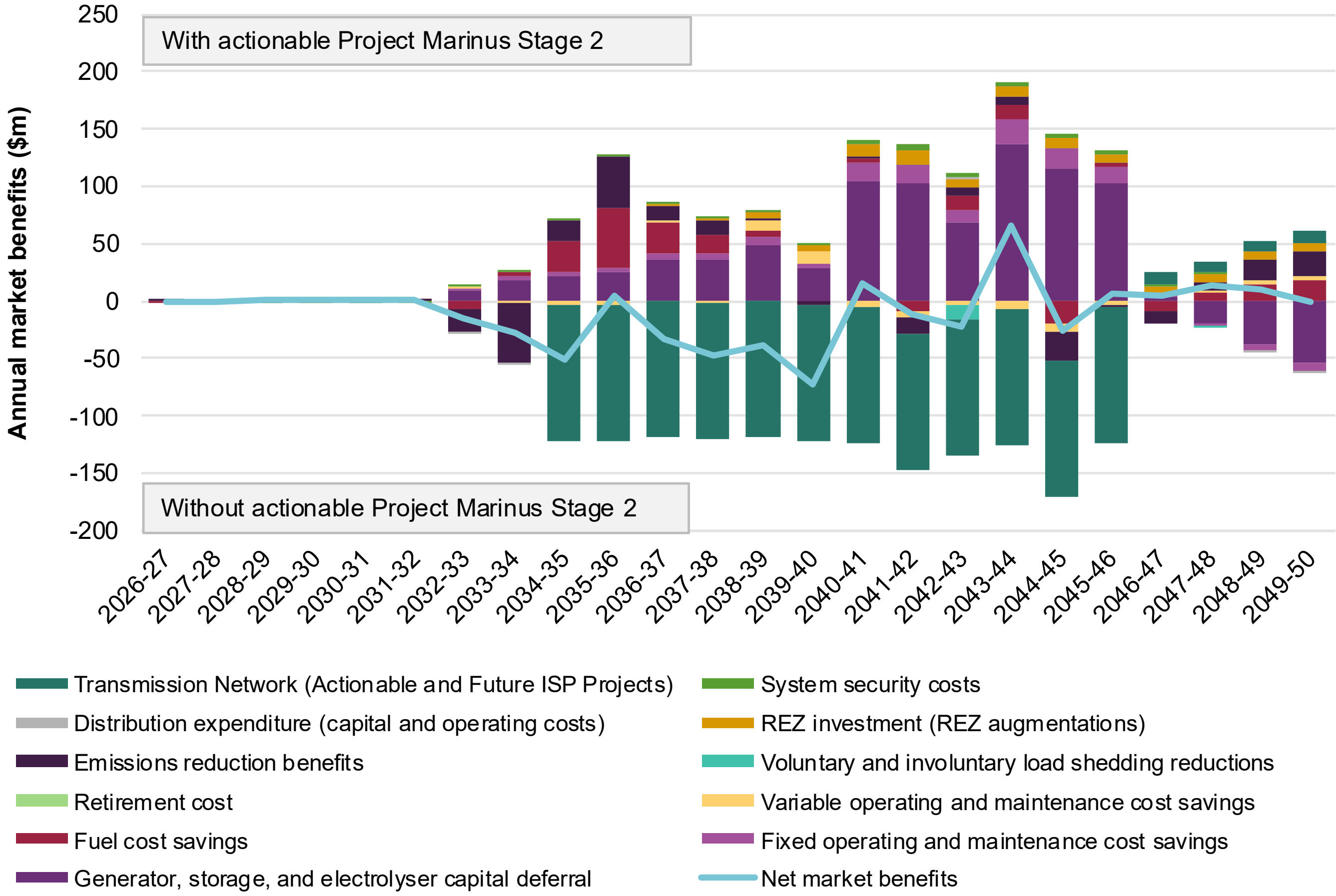
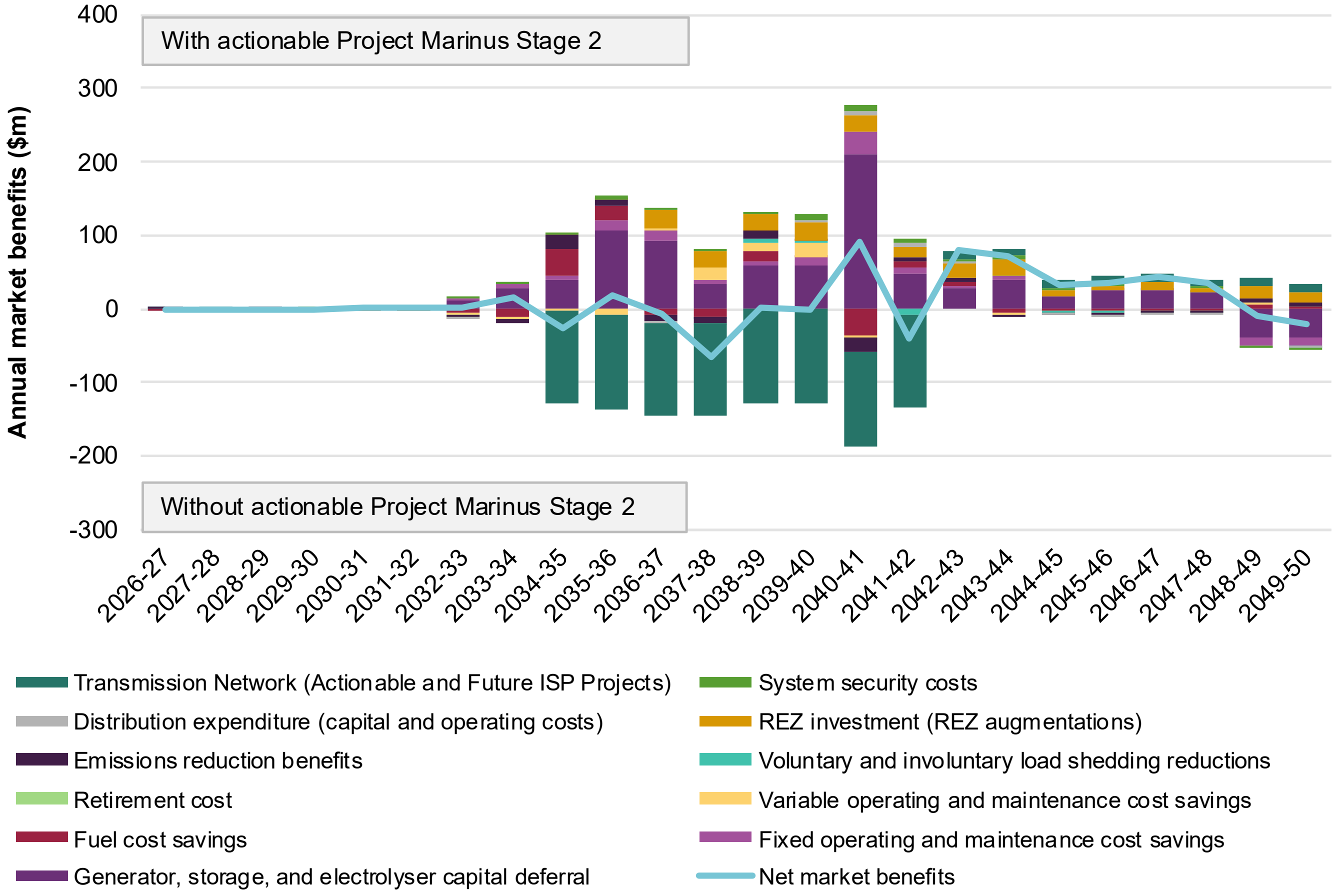


Figure 34 Net market benefits of actionable Project Marinus Stage 2 in *Accelerated Transition*



Project Marinus Stage 2 enables greater export of Tasmanian renewable energy, supported by the TRET, providing the mainland with access to this generation from the late 2030s. In all scenarios, delivering the project at an actionable timing results in higher levels of generation in Tasmania flowing to the rest of the NEM, particularly reducing overall generation in Victoria and New South Wales.

Delaying Project Marinus Stage 2 in *Step Change* requires building more than 1,000 MW of utility-scale solar and wind capacities in New South Wales and South Australia in the early 2040s, and almost 200 MW of utility-scale storage in Victoria (see **Figure 35** below). It leads to higher utilisation of gas generators around the NEM in the 2030s and associated increases in fuel and emissions costs of operating these existing generators. However, overall, the capital expenditure, fuel and emissions costs savings are outweighed by the cost of the project.

Similar dynamics apply to *Accelerated Transition* but on a larger scale (see **Figure 36** below), which result in positive net market benefits from delivering the project at an actionable timing. Not delivering the project at an actionable timing in *Accelerated Transition* results in increased hydro generation, while non-renewable generation remains relatively consistent across the outlook period.

In *Slower Growth*, as shown in **Figure 37**, the project's benefits interact with the ongoing availability of industrial loads in Tasmania, such that the project is more beneficial to manage surplus Tasmanian renewable generation, particularly if loads close. Delaying the project has the greatest impact on developments in *Slower Growth*, resulting in an increase of around 2 GW of utility-scale storage in Tasmania (to complement the VRE developed in the state to meet the TRET), and 0.5 GW of flexible gas in Greater Melbourne and Geelong to the early 2040s. Delivering the project at an actionable timing also avoids coal and gas generation in the middle of the outlook period, thereby avoiding the associated fuel and emission costs. This results in the net market benefits of delivering the project at an actionable timing being greatest in this scenario.

Figure 35 Comparison of capacity with and without an actionable Project Marinus Stage 2 in *Step Change*

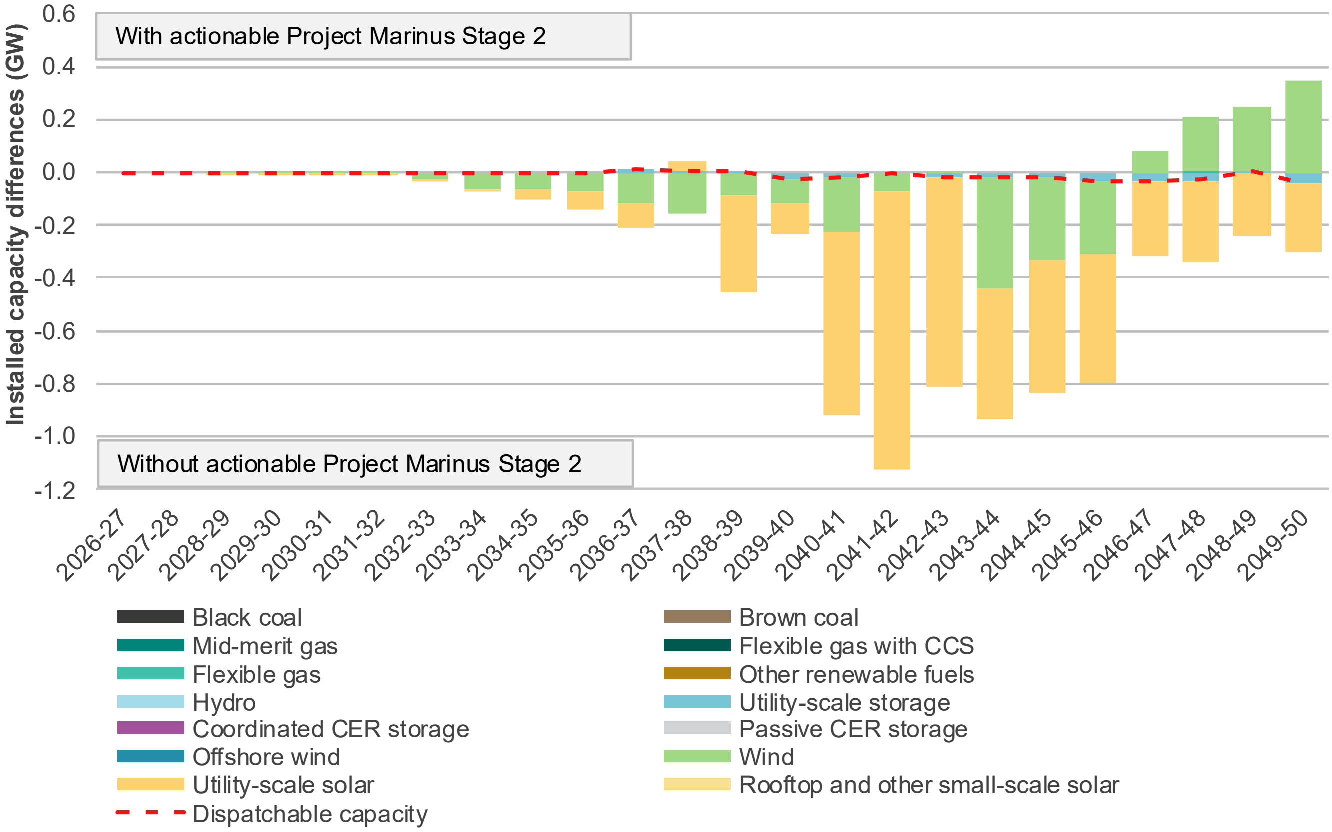


Figure 36 Comparison of capacity with and without an actionable Project Marinus Stage 2 in *Accelerated Transition*

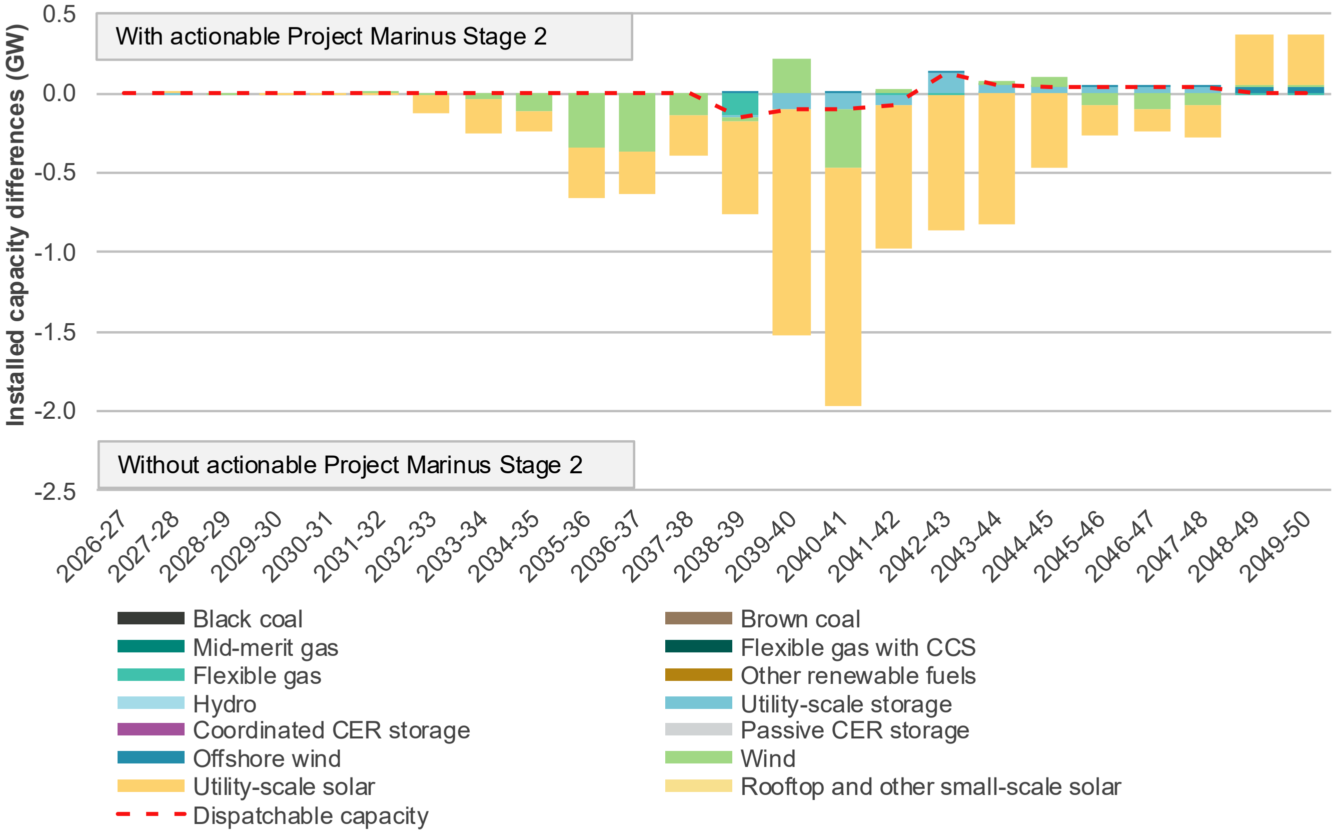
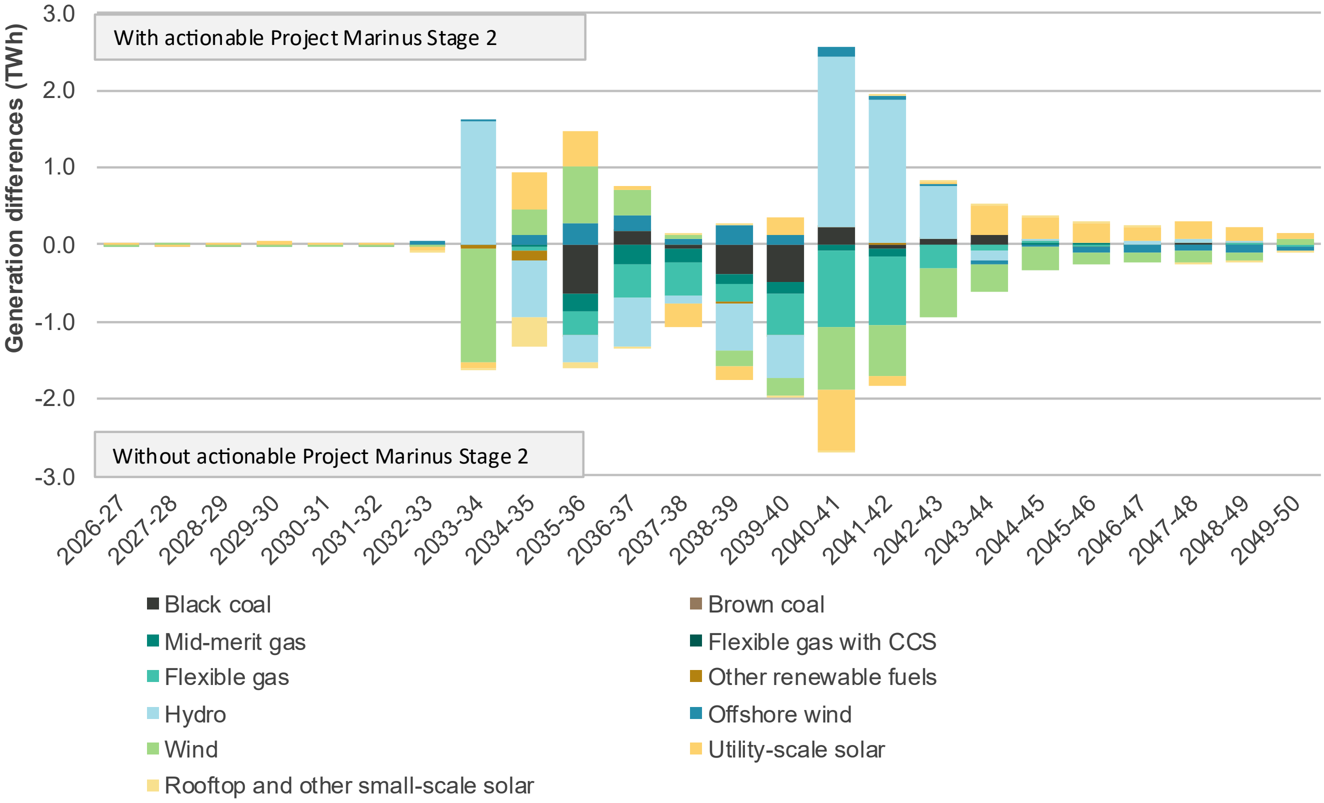


Figure 37 Comparison of annual generation with and without an actionable Project Marinus Stage 2 in *Slower Growth*



Assessing the regrets associated with not treating Project Marinus Stage 2 as an actionable project

Table 56 presents the weighted regrets and worst weighted regrets for CDP 4 and CDP 24 across all the scenarios. If the project's delivery is delayed until after the actionable window (2041-42), the regrets associated with the risk of under-investment in Project Marinus Stage 2 are largest in *Slower Growth*. Delaying the project would result in an increase in worst weighted regrets of $271 million.

Table 56 Weighted and worst weighted regrets of CDP 4 and CDP 24 ($ million) – Project Marinus Stage 2

	CDP 4 – with actionable Project Marinus Stage 2	CDP 24 – without actionable Project Marinus Stage 2	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	411	271
Step Change	101	50	-51
Accelerated Transition	43	59	17
Worst weighted regrets	140	411	271
Ranking based on worst weighted regrets	5	26	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Tasmania REZ Expansion

	North West Tasmania REZ option [T2 Option 1]	Central Highlands REZ option [T3 Option 1A]
EISD	July 2030	July 2030
Actionable window length	2 years (actionable in the Draft 2026 ISP)	4 years (actionable in the 2024 ISP, previously Waddamana to Palmerston transfer capability upgrade)
Reported cost[71]	$245 million (AEMO estimate) Class 5b (-50% to +50%)	$224 million (TNSP estimate) Class 4 (-30% to +50%)
Cost adjusted for transmission cost escalation	$267 million (*Slower Growth*, 2030-31) $268 million (*Step Change*, 2030-31) $273 million (*Accelerated Transition*, 2030-31)	$238 million (*Slower Growth*, 2030-31) $240 million (*Step Change*, 2030-31) $245 million (*Accelerated Transition*, 2030-31)
Flow path or REZ	North West Tasmania REZ	Central Highlands REZ
Capacity increase	800 MW	555 MW

The identified need for the Tasmania REZ Expansion is broader than the previous Waddamana to Palmerston capability upgrade project that was identified as an actionable project in the 2024 ISP. This Tasmania REZ Expansion project allows greater flexibility for TasNetworks to progress the project to meet the TRET following Project Marinus' development. Two options to facilitate development are considered in this ISP: North West Tasmania REZ option and the Central Highlands REZ option.

The North West Tasmania REZ option increases the capacity to connect and operate renewable generation development in the North West Tasmania REZ. The project has an EISD of July 2030 and is identified as optimal to be delivered at an actionable timing in the least-cost DPs for *Step Change* and *Accelerated Transition*, and immediately after its actionable window in *Slower Growth*. The option provides additional network capacity of 800 MW to support development of renewable generation in Tasmania, which would aid in meeting the region's policy targets and energy consumption in the future.

The previously-identified actionable project, Waddamana to Palmerston transfer capability upgrade, remains a viable option to meet this need. It has an EISD of July 2030 and was identified in the least-cost development path for *Accelerated Transition* only, in addition to the North West Tasmania REZ option. It would increase transfer capability by around 555 MW to support renewable generation development in Tasmania's Central Highlands REZ.

In *Accelerated Transition*, additional network augmentation is needed in both the North West Tasmania REZ and the Central Highlands REZ to support energy demand in Tasmania and the mainland, which is why a second REZ expansion option is identified as a future ISP project.

AEMO classifies the Tasmania REZ Expansion as an actionable ISP project and a second Tasmania REZ Expansion is classified as a future ISP project. The actionable project includes potential development of either the North West Tasmania REZ or the Central Highlands REZ. The future ISP project considers further development beyond the actionable scope. Its focus will depend on the outcomes of the TasNetworks RIT-T. For example, if the RIT-T identifies the North West Tasmania development as preferred, the future project may prioritise the Central Highlands REZ, and vice versa.

[71] 'Reported cost' refers to the estimate prepared by the TNSP, or by AEMO and reviewed by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

Assessing the relative market benefits of North West Tasmania REZ option via TOOT analysis

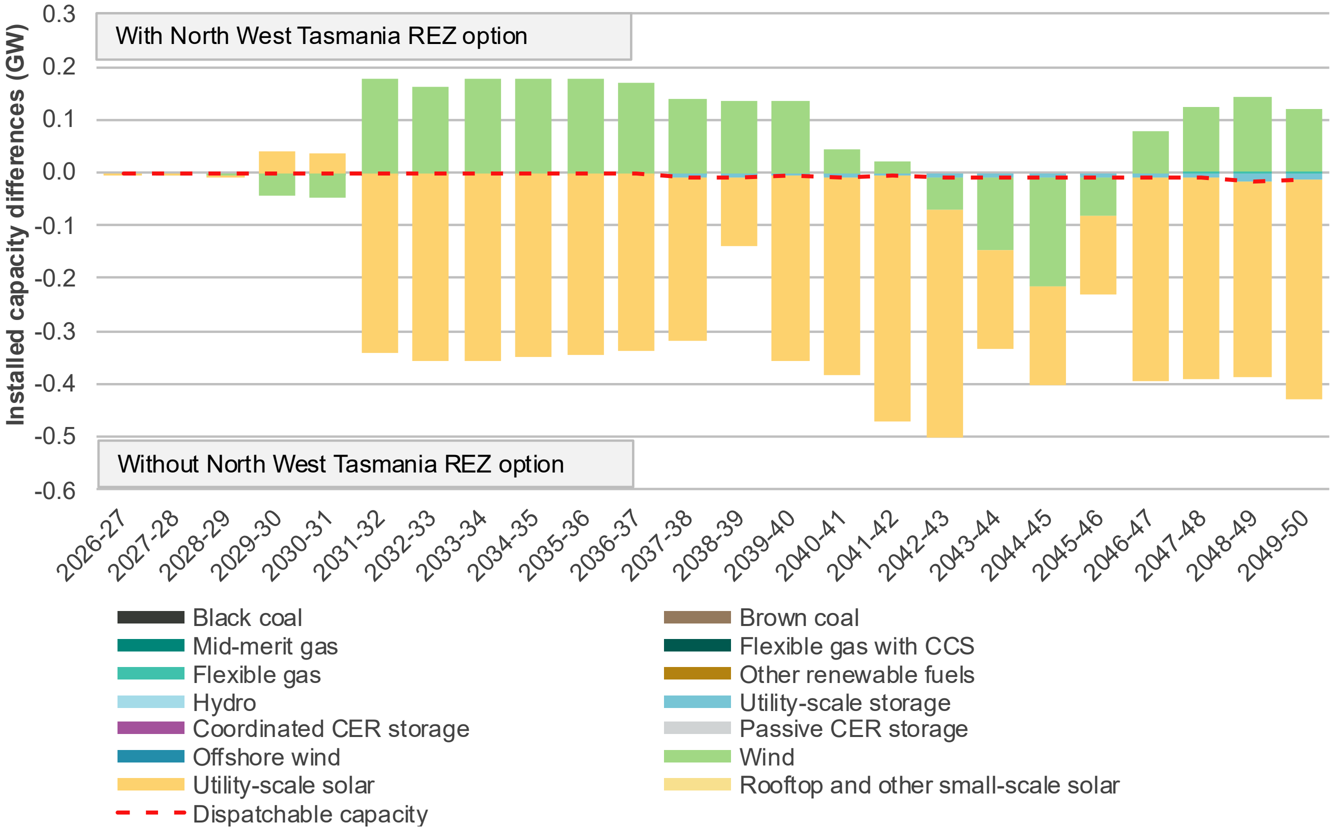
Table 57 shows relative market benefits of $66 million when delivering North West Tasmania REZ option at its EISD in *Step Change* compared with a case without the project.

The key source of benefits for this option is the deferral of over 400 MW of mid-scale and utility-scale solar in Tasmania and associated distribution network developments that would otherwise be needed to efficiently meet the TRET. With the North West Tasmania REZ, 200 MW of higher resource quality wind and utility-scale is developed instead, as shown in **Figure 38**. This reduces generator capital costs, maintenance costs, and distribution network costs that are otherwise built to accommodate alternative new entrant renewable capacities in the TOOT case, as illustrated in **Figure 39**.

Table 57 Relative market benefits of North West Tasmania REZ option in *Step Change*

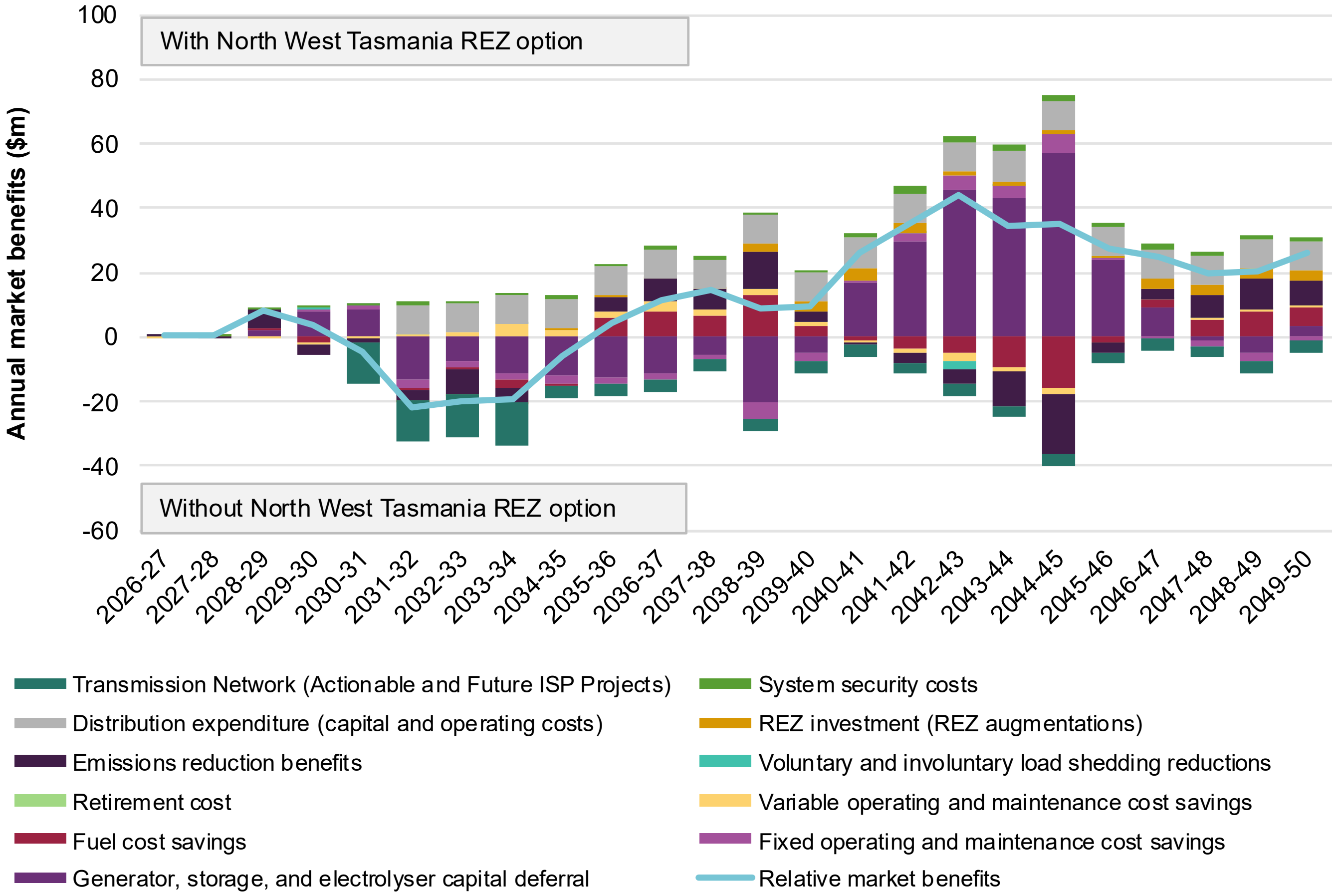
Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	28
Fixed operating and maintenance cost savings	-5
Fuel cost savings	7
Variable operating and maintenance cost savings	6
Retirement cost	0
Voluntary and involuntary load shedding reductions	-1
Emissions reduction benefits	0
REZ investment (REZ augmentations)	9
Distribution expenditure (capital and operating costs)	63
System security costs	8
Gross market benefits	**116**
Transmission Network (Actionable and Future ISP Projects)	-50
Total relative market benefits	**66**

Figure 38 Comparison of capacity with and without North West Tasmania REZ option in *Step Change* (at 2030-31)



Utility-scale solar capacity in this figure includes mid-scale and utility-scale solar developments.

Figure 39 Annual relative market benefits of North West Tasmania REZ option in *Step Change* (2030-31)



Assessing the net market benefits of North West Tasmania REZ option as an actionable project

CDP 4 has delivery of North West Tasmania REZ option at its EISD, whereas CDP 25 features delivery of the project in 2032-33, after the project's actionable window. The benefits of an actionable North West Tasmania REZ option by scenario are displayed in **Table 58** below.

Table 58 Comparing net market benefits between CDP 4 and CDP 25 ($ billion) – North West Tasmania REZ option

	CDP 4 – with actionable North West Tasmania REZ option	CDP 25 – without actionable North West Tasmania REZ option	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.29	10.29	0.01
Step Change	29.55	29.50	-0.05
Accelerated Transition	42.55	42.50	-0.05
Weighted net market benefits	27.86	27.82	-0.03
Ranking based on weighted net market benefits	1	9	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Compared to delivery in 2032-33, an actionable North West Tasmania REZ option delivers $30 million more weighted net market benefits, - $46 million in *Step Change* and $54 million in *Accelerated Transition*, but a reduction in net market benefit of $6 million in *Slower Growth* and. The majority of the benefits are due to avoided capital expenditure on expanding distribution networks to support access to mid-scale utility-scale solar capacity to meet the TRET.

Delaying North West Tasmania REZ option in *Step Change* requires building around an additional 400 MW of mid-scale generation capacity in Tasmania, rather than a smaller amount of wind in the North West REZ enabled by this project, alongside a small amount of utility-scale solar.

Assessing the regrets associated with North West Tasmania REZ option as an actionable project

Table 59 presents the weighted regrets and worst weighted regrets for CDP 4 and CDP 25 across all the scenarios. If the project's delivery is delayed until well after the actionable window, the regrets associated with the risk of under-investment in North West Tasmania REZ option are largest in *Step Change*. Delaying the project to 2032-33 would result in a reduction in worst weighted regrets (from risk of over-investment in *Slower Growth*) of $2 million.

Table 59 Weighted and worst weighted regrets of CDP 4 and CDP 25 ($ million) – North West Tasmania REZ option

	CDP 4 – with actionable North West Tasmania REZ option	CDP 25 – without actionable North West Tasmania REZ option	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	140	139	-2
Step Change	101	122	21
Accelerated Transition	43	57	15
Worst weighted regrets	140	139	-2
Ranking based on worst weighted regrets	5	4	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the relative market benefits of Central Highlands REZ option via TOOT analysis

Table 60 shows a reduction in relative market benefits of $42 million when delivering Central Highlands REZ option at its EISD in *Step Change* compared with a case without the project. The project does not defer significant utility-scale capacity if delivered at an actionable timing, with minimal impact in Tasmania from 2032 onwards.

Table 60 Relative market benefits of Central Highlands REZ option in *Step Change*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	40
Fixed operating and maintenance cost savings	7
Fuel cost savings	-1
Variable operating and maintenance cost savings	-1
Retirement cost	0
Voluntary and involuntary load shedding reductions	1
Emissions reduction benefits	-0
REZ investment (REZ augmentations)	0
Distribution expenditure (capital and operating costs)	0
System security costs	1
Gross market benefits	**47**
Transmission Network (Actionable and Future ISP Projects)	-88
Total relative market benefits	**-42**

Assessing the net market benefits of Central Highlands REZ option as an actionable project

The net market benefits of the Central Highlands REZ option can be assessed by comparing CDP 4 (which features the project beyond 2049-50 in *Step Change*) and CDP 27 which features the project at an actionable timing. As **Table 61** highlights, the project delivers positive benefits in *Accelerated Transition* ($14 million) when delivered at an actionable timing, while there is a reduction of net market benefits in *Step Change* ($42 million) and *Slower Growth* ($31 million). Overall, there is a reduction in weighted net market benefits of $20 million if Central Highlands REZ was delivered at its EISD.

Table 61 Comparing net market benefits between CDP 27 and CDP 4 ($ billion) – Central Highlands REZ option

	CDP 27– with actionable Central Highlands REZ option	CDP 4 – without actionable Central Highlands REZ option	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.25	10.29	0.03
Step Change	29.50	29.55	0.04
Accelerated Transition	42.56	42.55	-0.01
Weighted net market benefits	27.83	27.86	0.02
Ranking based on weighted net market benefits	6	1	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Delivering this project at an actionable timing in *Step Change* supports utility-scale solar and wind generation to be exported from Tasmania to the rest of the NEM, which displaces some utility-scale solar generation from several mainland regions. Similarly, in *Slower Growth,* delivering this project at an actionable timing avoids 400 MW of mid-scale generation and storage in Tasmania and replaces it with 200 MW of wind in Tasmania. However, in both scenarios, this does not provide sufficient cost savings to warrant the capital outlay required for the project.

In *Accelerated Transition*, delaying the project requires developing additional mid-scale generation in Tasmania to meet demand instead of a smaller amount of wind in the Central Highlands REZ. This results in a small net market benefit for delivering the project at an actionable timing in this scenario.

Assessing the regrets associated with Central Highlands REZ option as an actionable project

Table 62 presents the impact on weighted and worst weighted regrets of delivering the project at an actionable timing. While regret in *Accelerated Transition* decreases, it is the risk of over-investment in *Slower Growth* that ultimately drives a minor increase in worst weighted regret of $8 million if the project was delivered at an actionable timing.

Table 62 Weighted and worst weighted regrets of CDP 27 and CDP 4 ($ million) – Central Highlands REZ option

	CDP 27 – with actionable Central Highlands REZ option	CDP 4 – without actionable Central Highlands REZ option	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	149	140	-8
Step Change	120	101	-19
Accelerated Transition	39	43	4
Worst weighted regrets	149	140	-8
Ranking based on worst weighted regrets	7	5	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

A6.6.4 Assessing projects that no longer deliver benefits at an actionable timing

Central Queensland to Southern Queensland Expansion

	Auburn River Switching Station [SQ-CQ Option 2]	Central Queensland to Southern Queensland Expansion [SQ-CQ Option 5]
EISD	December 2031	December 2031
Actionable window length	4 years (not previously actionable)	4 years (actionable in the 2024 ISP)
Reported cost[72]	$59 million Class 5b (-50% to +50%)	$3,751 million Class 5b (-50% to +50%)
Cost adjusted for transmission cost escalation	$73 million (*Accelerated Transition*, 2040-41)	$5,043 million (*Accelerated Transition*, 2047-48)
Flow path or REZ	Southern Queensland to Central Queensland	Southern Queensland to Central Queensland
Capacity increase	0 MW forward/300 MW reverse	3,150 MW forward / 1,900 MW reverse

Note: Both projects are part of the Central to Southern Queensland Expansion project.

The Central Queensland to Southern Queensland Expansion (formerly Queensland SuperGrid South) is a new 500 kV line allowing for additional transfer capacity in both directions in the flow path between Southern Queensland and Central Queensland. Since this option was found actionable in the 2024 ISP, it has an actionable window of four years. It also encompasses Auburn River Switching Station, which is a pre-requisite to the flow path augmentation. It also requires the prior delivery of both the Gladstone Project and the Brisbane Area 275 kV Reinforcement.

[72] 'Reported cost' refers to the estimate prepared by AEMO and reviewed by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

A key benefit of Central Queensland to Southern Queensland Expansion in the 2024 ISP was providing access to Borumba Pumped Hydro. However, considering new information provided by Powerlink, the project proponent, Borumba Pumped Hydro, can be connected to the network without the completion of Central Queensland to Southern Queensland Expansion, which reduces the benefits of delivering Central Queensland to Southern Queensland Expansion at an actionable timing compared with the 2024 ISP.

Both Auburn River Switching Station and Central Queensland to Southern Queensland Expansion have been found as most beneficial for consumers if delivered in 2040-41 and 2047-48 respectively in the least-cost DP for *Accelerated Transition*, while neither project delivers benefits within the outlook period in *Step Change* and *Slower Growth*.

Assessing the net market benefits of Central Queensland to Southern Queensland Expansion as actionable project

As **Table 63** highlights, delivering this project at an actionable timing results in a decrease in net market benefits in all scenarios ($1.41 billion in *Slower Growth,* and $1.37 billion in *Step Change* and $0.99 billion in *Accelerated Transition* respectively). Therefore, Central Queensland to Southern Queensland Expansion has been identified as a future ISP project rather than an actionable project in this 2026 ISP.

Table 63 Comparing net market benefits between CDP 8 and CDP 4 ($ billion) – Central Queensland to Southern Queensland Expansion

	CDP 8 – with actionable Central Queensland to Southern Queensland Expansion	CDP 4 – without actionable Central Queensland to Southern Queensland Expansion	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	8.88	10.29	1.41
Step Change	28.18	29.55	1.37
Accelerated Transition	41.56	42.55	0.99
Weighted net market benefits	26.58	27.86	1.28
Ranking weighted net market benefits	30	1	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change*, delivering Central Queensland to Southern Queensland Expansion at an actionable timing reduces the need to import renewable energy from New South Wales, and instead better enables renewable energy capacity developed in Central and Southern Queensland REZs to service load across Queensland. While this does provide limited generator and storage capital expenditure benefits through a more efficient system, it does not outweigh the cost of the project.

In *Slower Growth* the outcome is similar, although the benefits stem less from avoided capital expenditure. Instead, the project avoids emission and fuel costs as utility-scale solar and wind developed in Queensland displace coal and gas-powered generation in Queensland and New South Wales.

In *Accelerated Transition,* the project when delivered at an actionable timing delivers gross market benefits by delaying the development of up to 900 MW of utility-scale storage and 3 GW of utility-scale solar in Queensland in the 2040s. Instead, it enables existing wind capacity developed in New South Wales and Southern Queensland to better meet the load across Queensland. Given how late in the outlook period these benefits are projected, the net market benefits of delivering the project at an actionable timing are negative.

Assessing the regrets associated with Central Queensland to Southern Queensland Expansion as an actionable project

Table 64 presents the weighted and worst weighted regrets of both CDPs. Delivering the project at an actionable timing increases regrets across all scenarios.

Table 64 Weighted and worst weighted regret of CDP 8 and CDP 4 ($ million) – Central Queensland to Southern Queensland Expansion

	CDP 8 – with actionable Central Queensland to Southern Queensland Expansion	CDP 4 – without actionable Central Queensland to Southern Queensland Expansion	Change in weighted regrets associated with non-actionable delivery of the projects[A]
Slower Growth	520	140	-380
Step Change	730	101	-630
Accelerated Transition	311	43	-268
Worst weighted regrets	730	140	-590
Ranking based on worst weighted regrets	29	5	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Queensland – New South Wales Interconnector (QNI) Connect

	NNSW-SQ Option 2
EISD	March 2034
Actionable window length	4 years (actionable in 2024 ISP)
Reported cost[73]	$2,989 million (Total project cost) Class 5b (±50%) (NSW) Class 5 (+50%/-30%) (QLD)
Cost adjusted for transmission cost escalation	$3,495 million (*Slower Growth*, 2040-41) $3,630 million (*Step Change*, 2041-42) $3,835 million (*Accelerated Transition*, 2041-42)
Flow path or REZ	Northern New South Wales to Southern Queensland
Capacity increase	1,260 MW forward/1,700 MW reverse

QNI Connect provides additional interconnection between New South Wales and Queensland. The project was previously declared an actionable project in the 2024 ISP and as such has a four-year actionable window with an EISD of March 2034. It provides an increase of 1,260 MW of transfer capacity from New South Wales to Queensland and 1,700 MW in the reverse direction towards New South Wales.

This augmentation requires the prior development of the New England REZ Network Infrastructure Project, which is now assumed to be anticipated, with delivery in January 2034 (see section A6.6.2).

QNI Connect would improve sharing of firming capacity between Queensland and southern NEM regions, including the deep storage Borumba Pumped Hydro project, particularly as coal generators retire. It is optimal if delivered outside of its

[73] 'Reported cost' refers to the estimate provided by the TNSPs. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

actionable window in all three scenarios (2041-42 in *Step Change* and *Accelerated Transition*, and 2040-41 in *Slower Growth)*.

Assessing the net market benefits of QNI Connect as an actionable project

Table 65 presents the net market benefits associated with delivering QNI Connect as an actionable project by comparing CDP 4 and CDP 9 (which is similar to CDP 4 but features the project's delivery at an actionable timing).

Progressing QNI Connect as actionable decreases net market benefits in *Step Change* and *Accelerated Transition* by $199 million and $155 million respectively, relative to the benefits accrued if the project were delivered as a future project. In *Slower Growth*, however, delivering the project at an actionable timing would increase net market benefits by $167 million, as it enables a reduction in the usage of coal generation in Queensland by unlocking renewable energy imported from the other NEM regions, as explained below. Overall, delivering the project at an actionable timing will decrease net market benefits by $90 million, weighted across all three scenarios.

Table 65 Comparing net market benefits between CDP 9 and CDP 4 ($ billion) – QNI Connect

	CDP 9 – with actionable QNI Connect	CDP 4 – without actionable QNI Connect	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	10.45	10.29	-0.17
Step Change	29.35	29.55	0.20
Accelerated Transition	42.40	42.55	0.15
Weighted net market benefits	27.77	27.86	0.09
Ranking weighted net market benefits	12	1	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change*, delivering QNI Connect at an actionable timing results in limited gross benefits stemming from avoided VRE capacity in both Queensland and New South Wales. No dispatchable capacity is deferred with the additional interconnection in this scenario.

In *Slower Growth*, the project delivers significant emission reduction benefits under CDP 9, as coal generation is reduced with improved access to Northern Queensland, Hunter-Central Coast REZ, and offshore wind in Victoria. This results in an increase in net market benefits associated with an actionable timing in this scenario.

Assessing the regrets associated with QNI Connect as an actionable project

Table 66 below presents the weighted and worst weighted regrets associated with this augmentation option across the scenarios. Bringing the delivery of the project forward to an actionable timing results in a $52 million increase in worst weighted regret compared to CDP4, driven by the risk of over-investment in *Step Change*. The project does result in a decrease in regrets in *Slower Growth* (approximately $45 million) when delivered at an actionable timing, due to the project delivering benefits at an actionable timing in the scenario.

Table 66 Weighted and worst weighted regret of CDP 9 and CDP 4 ($ million) – QNI Connect

	CDP 9 – with actionable QNI Connect	CDP 4– without actionable QNI Connect	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	95	140	45
Step Change	192	101	-91
Accelerated Transition	84	43	-42
Worst weighted regrets	192	140	-52
Ranking based on worst weighted regrets	12	5	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

QNI Connect is no longer identified as actionable in the 2026 ISP. This reflects higher real project costs relative to the 2024 ISP, alongside changes in system conditions that reduce its benefits. These include delayed coal retirements in Queensland, more anticipated generation and storage developments, the abolishment of the Queensland Renewable Energy Target, and lower demand in *Accelerated Transition* due to revised hydrogen demand forecasts.

Waddamana to Palmerston transfer capability upgrade

	Central Highlands REZ option [T3 Option 1A]
EISD	July 2030
Actionable window length	4 years (actionable in the 2024 ISP)
Reported cost[74]	$224 million Class 4 (-30% to +50%)
Cost adjusted for infrastructure inflation	$238 million (*Slower Growth*, 2030-31) $240 million (*Step Change*, 2030-31) $245 million (*Accelerated Transition*, 2030-31)
Flow path or REZ	Central Highlands REZ
Capacity increase	555 MW

AEMO has investigated the benefits of delivering the Central Highlands REZ option as a separate project as described in the Waddamana to Palmerston transfer capability upgrade project in the 2024 ISP. As outlined in the previous section, the Central Highlands REZ option is a potential option to meet the needs of the Tasmania REZ Expansion project, alongside a North West Tasmania REZ option (see Section A6.6.3).

As described in the previous section, AEMO classifies the Tasmania REZ Expansion as an actionable ISP project and a second Tasmania REZ Expansion is classified as a future ISP project. The future Second Tasmania REZ Expansion project (previously Waddamana to Palmerston transfer capability upgrade) will depend on the outcomes of the TasNetworks RIT-T. For example, if the RIT-T identifies the North West Tasmania development as preferred, the future project may prioritise the Central Highlands REZ, and vice versa.

[74] 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for infrastructure inflation' (beyond economy wide inflation) reflects the same estimate restated to a common infrastructure cost basis to evaluate projects at different times and across different scenarios.

Northern Transmission (NTx) Project (formerly Mid North South Australia REZ Expansion)

	Northern Transmission Project "South" [MN1 Option 2]
EISD	July 2029[75]
Actionable window length	4 years (actionable in the 2024 ISP)
Reported cost[76]	$1,429 million[77] Class 5b (±50%)
Cost adjusted for transmission cost escalation	$1,836 million (*Accelerated Transition*, 2041-42)
Flow path or REZ	Mid North SA REZ group constraints (MN1 and MN2)[78]
Capacity increase	1,200 MW (MN1)

In the 2024 ISP, AEMO identified that a transmission augmentation in the Mid North of South Australia, which supports flows south to Adelaide, was an actionable ISP project. Since the commencement of the RIT-T for the project, ElectraNet has identified additional options to those assessed in the 2024 ISP. As such, the project (including all its alternative variants) has a four-year actionable window in this ISP.

The project has been renamed to Northern Transmission Project, with significant scope and cost revisions as part of the RIT-T. As noted in the recently released Project Assessment Draft Report (PADR)[79] published by ElectraNet in April 2026, the previous candidate ISP option from the 2024 ISP is "not commercially feasible" due to additional future costs involved for expanding the network with that option, elevated bushfire risk for that option, and "the need to quarantine the existing spare bays at Para for future expansion".

The Northern Transmission Project is composed of two legs – the southern leg which upgrades the transmission network between Mid-North South Australia and Adelaide area, and the northern leg which is an augmentation of the flow path between Central South Australia and Northern South Australia – which were both tested in the core scenario analysis.

The southern leg is a new 275 kV augmentation focused on supporting load development in Central South Australia (particularly in the Adelaide area) by increasing network capacity into Adelaide from Mid-North South Australia REZs, Project EnergyConnect, and Murraylink by 1,200 MW. The augmentation of the southern leg costs $1,836 million[80] (if delivered in 2041-42, which is the optimal timing for the project in the least-cost DP for A*ccelerated Transition)*. The project is not found to be optimal to deliver within the outlook period in the other two scenarios.

Delivery of the augmentation to the northern leg was not found to provide positive net market benefit in any of the scenarios.

[75] AEMO has modelled the project with an EISD of July 2029. The NTx Project Assessment Draft Report (PADR) notes for this scope that commissioning would commence from "2029/30". See https://ntxproject.com.au/wp-content/uploads/2026/04/NTx-PADR.pdf.

[76] 'Reported cost' refers to the estimate provided by the TNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[77] This is the $2025 cost of this option provided by ElectraNet. Note that ElectraNet has advised that approximately $23 million of this amount relates to approved early works costs. These costs have therefore been excluded from the 2026 ISP CBA with the AER's CBA Guidelines.

[78] These group constraints limit Riverland, Mid-North South Australia and Yorke Peninsula REZ generation, flows from Northern South Australia to Central South Australia, and interconnector imports to South Australia across the Project EnergyConnect and Murraylink interconnectors.

[79] At https://ntxproject.com.au/project-assessment-draft-report-published-for-the-northern-transmission-project/.

[80] The cost of this option has more than tripled compared to the candidate ISP option in the 2024 ISP (which ElectraNet's Project Assessment Report for Northern Transmission Project considers "*not commercially feasible*"). The cost of the option considered in the 2026 ISP is also exclusive of approximately $23 million of approved early works costs. These costs have been excluded from the 2026 ISP CBA in accordance with the AER's CBA Guidelines.

Since this project (both legs) has only been found to deliver positive net market benefits in *Accelerated Transition*, yet was found actionable in the 2024 ISP, AEMO has conducted extended analysis to ascertain the costs and merits of the project under alternative assumptions.

Assessing the net market benefits of Northern Transmission Project

The benefits of Northern Transmission Project as an actionable project can be assessed by comparing CDP 4 against CDP 28 (where Northen Transmission Project is delivered at an actionable timing). As seen in **Table 67**, delivering the project at an actionable timing would decrease weighted net market benefits by around $500 million. The disbenefit is lowest in *Accelerated Transition*; the project is optimal to be developed in the 2040s in that scenario.

Table 67 Comparing net market benefits between CDP 28 and CDP 4 ($ billion) – Northern Transmission Project

	CDP 28 – with actionable Northern Transmission Project	CDP 4 – without actionable Northern Transmission Project	Change in net market benefits associated with non-actionable delivery of the project[A]
Slower Growth	9.69	10.29	0.59
Step Change	28.99	29.55	0.56
Accelerated Transition	42.25	42.55	0.30
Weighted net market benefits	27.36	27.86	0.50
Ranking based on weighted net market benefits	26	1	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Accelerated Transition,* the project avoids more expensive mid-scale generation to be developed from 2034-35 onwards in Central South Australia; it instead drives the development of utility-scale solar in Central South Australia. In this scenario, this project does not deliver sufficient benefits to warrant delivery at its actionable timing. The project does deliver benefits during the 2040s by reducing voluntary load shedding (mainly in South Australia) and more expensive development of utility-scale solar, wind, and additional REZ transmission in Victoria and Northern South Australia.

This scenario includes materially higher industrial load growth in South Australia, demonstrating that in a higher growth scenario, the benefits of the project would increase and its development may be an important consideration in such a future.

Assessing the regrets associated with Northern Transmission Project as an actionable project

Table 68 shows the regrets associated with actionable delivery of the Northern Transmission Project. There is an increase in regrets if delivered at an actionable timing due to the risk of over-investment present in *Step Change* were that scenario to eventuate. Worst weighted regrets by making the project actionable increase by $216 million compared to CDP 4.

Table 68 Weighted and worst weighted regrets of CDP 28 and CDP 4 ($ million) – Northern Transmission Project

	CDP 28 – with actionable Northern Transmission Project	CDP 4 – without actionable Northern Transmission Project	Change in weighted regrets associated with non-actionable delivery of the project[A]
Slower Growth	301	140	-160
Step Change	356	101	-256
Accelerated Transition	124	43	-81
Worst weighted regrets	356	140	-216
Ranking based on worst weighted regrets	24	5	NA

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Extended analysis for Northern Transmission Project

The PADR for the Northern Transmission Project identified that the benefits of the project are linked to growing demand in South Australia, alleviating congestion between the Mid North and Adelaide, and increasing access to renewable resources.

Considering that the project has been previously found as actionable in the 2024 ISP, and the potential significance of losing that status in the 2026 ISP for an in-flight project that is extensively engaging with communities under its RIT-T assessment, AEMO has extended the analyses in this ISP to further understand the impact of key assumptions that may differ between the ISP and the assumptions used in the PADR.

The first analysis focuses on the impact on net market benefits of the Northern Transmission Project if development of mid-scale generation and storage (which is a new consideration in the 2026 ISP) was not available, unlike in the core scenarios. In *Step Change* and *Accelerated Transition*, mid-scale generation and storage connected within the distribution network across Central South Australia is the preferred alternative generation development than utility-scale developments in Mid-North South Australia, if Northern Transmission Project is not delivered. This additional analysis showed in *Accelerated Transition* that if development of mid-scale generation was not plausible nor credible, the gross market benefits of the project improved by $70 million. While the project would provide a material saving if more costly alternatives were needed, the scale of these gross benefits is not sufficient to offset the project's cost at an actionable timing to produce net market benefits.

Secondly, very high industrial development and data centre load growth across the NEM was examined in the *Higher Demand* sensitivity (discussed in Section A6.8.2). This included higher industrial and data centre load growth, including in South Australia, than assumed in *Step Change*, providing insights on the project's potentially improved benefits to support increased load developments. The sensitivity analysis shows that the benefits of an actionable delivery for the project increases by $86 million compared to its benefits in *Step Change*, although it remains insufficiently beneficial to deliver positive net market benefits.

In the PADR, ElectraNet finds that the project delivers additional resilience benefits for South Australian consumers, such as improved system performance during extreme wind and bushfire events. These benefits are not explicitly assessed in the ISP. AEMO considers that resilience benefits are more appropriately explored in the RIT-T.

The extended analysis described above demonstrated that with alternative assumptions there would be increased benefits of the project being developed at its actionable timeframe, though insufficient benefits to justify retaining its actionable status. With the project providing positive net market benefits in *Accelerated Transition*, under higher load growth assumptions, it remains on the ODP as a future ISP project.

Given the project remains on the ODP and there is an active RIT-T underway, AEMO considers ElectraNet should conclude the RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options. Continuing community engagement may also help to narrow the corridor and reduce uncertainty for affected communities, while ensuring community considerations are reflected in future planning and decision-making.

A6.6.5 Distribution network development opportunities

Several distribution network augmentations have also been considered as part of the process for identifying the least-cost DPs under each scenario for this ISP. As they cannot be directly actioned under the ISP framework, they are not assessed through the CDP collection. They were, however, found to contribute to the least cost pathways to developing the NEM by providing access to lower cost sources of energy in the distribution network.

The following sections discuss the benefits of these projects. See Appendix A9 Demand Side Factors Statement for further information on general development opportunities to support CER operation in the distribution network.

Hunter-Central Coast REZ Expansion

	N9b Option 2a[81]
EISD	December 2030
Reported cost[82]	$636 million Class 5b (±50%)
Cost adjusted for transmission cost escalation	$641 million (*Slower Growth*, 2030-31) $644 million (*Step Change*, 2030-31) $659 million (*Accelerated Transition*, 2030-31)
Flow path or REZ	Hunter-Central Coast (Sydney, Newcastle and Wollongong side)
Capacity increase	900 MW

Hunter-Central Coast REZ Expansion complements the committed Hunter-Central Coast REZ Network Infrastructure Project, by providing an additional 900 MW of network capacity to the Sydney, Newcastle and Wollongong side of the Hunter-Central Coast REZ[83]. It allows for increased access to VRE generation within the Sydney, Newcastle and Wollongong sub-region, helping efficiently supply loads within the sub-region without being subject to flow path transfer limitations associated with VRE developments in other sub-regions.

While Hunter-Central Coast REZ Expansion has not been found optimal if delivered within the outlook period in the least-cost DPs for *Step Change* and *Slower Growth*, it is most beneficial at its EISD in *Accelerated Transition*; the drivers for this are discussed in the following section.

[81] In Appendix A5, Hunter-Central Coast REZ Expansion covers both an augmentation project in Sydney, Newcastle, and Wollongong sub-region and an augmentation project in Central New South Wales sub-region. The augmentation project being discussed in the appendix is the project in Sydney, Newcastle, and Wollongong sub-region.

[82] 'Reported cost' refers to the estimate provided by the TNSP and DNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[83] In the 2026 ISP, AEMO has modelled the Hunter-Central Coast REZ as two sub-REZs. One sub-REZ is in Central New South Wales (REZ N9a) and one is in Sydney, Newcastle and Wollongong (REZ N9b). See the supporting 2026 ISP Inputs and Assumptions Workbook for more details.

Assessing the relative market benefits of Hunter-Central Coast REZ Expansion via TOOT analysis

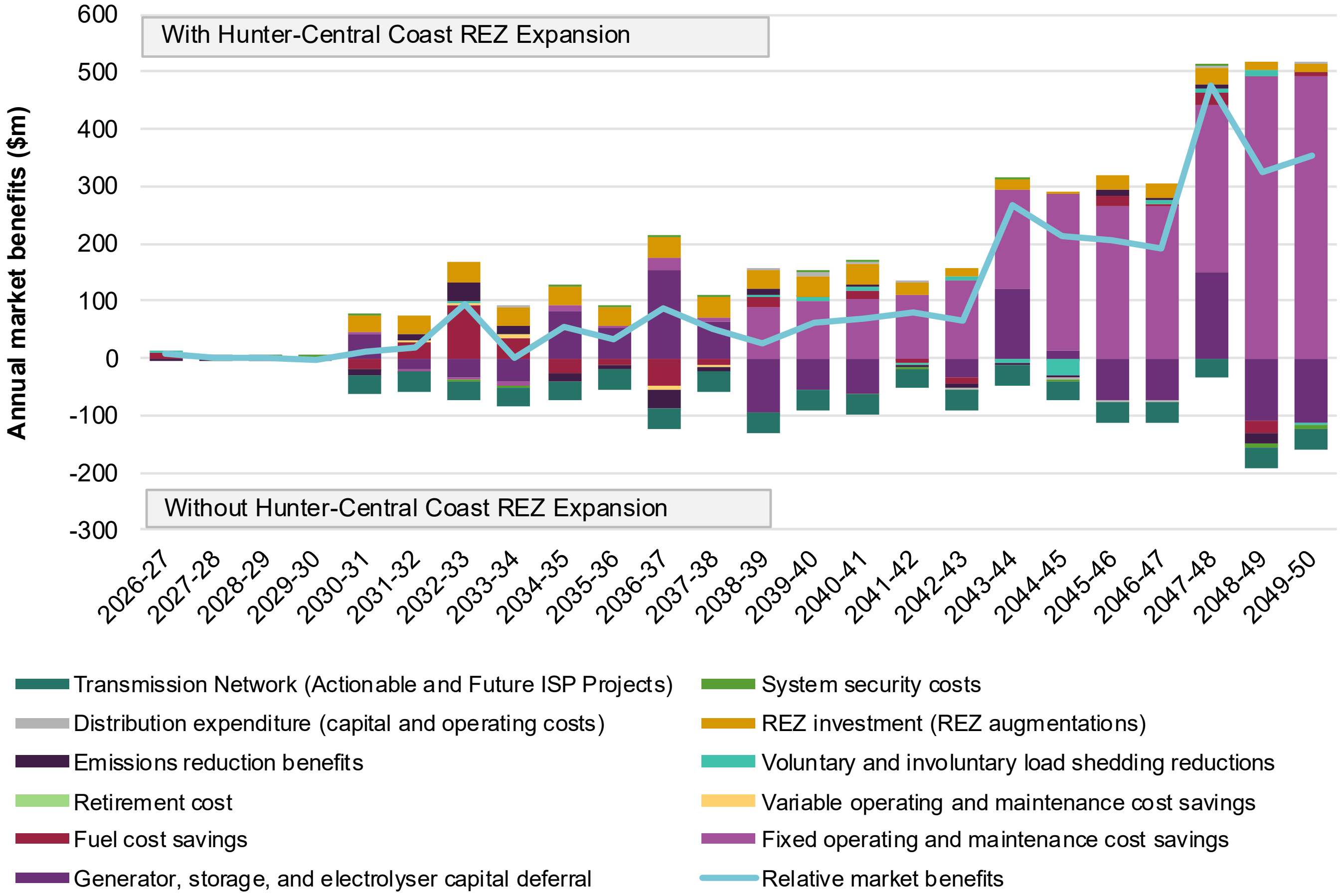
In *Step Change* and *Slower Growth*, the Sydney Ring North (Hunter Transmission Project) and Sydney Ring South augmentations discussed in previous sections largely fulfil the role of enabling supply to Sydney, Newcastle and Wollongong, meaning further augmentation of Hunter-Central Coast REZ is not necessary. However, there are significant relative market benefits associated with delivering Hunter-Central Coast REZ Expansion at its EISD in *Accelerated Transition* compared to a case without it in CDP 4, as shown in **Table 69**, suggesting that in higher growth futures, the project may provide material benefits.

Table 69 Relative market benefits of Hunter-Central Coast REZ Expansion in *Accelerated Transition*

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	34
Fixed operating and maintenance cost savings	688
Fuel cost savings	54
Variable operating and maintenance cost savings	4
Retirement cost	0
Voluntary and involuntary load shedding reductions	5
Emissions reduction benefits	-0
REZ investment (REZ augmentations)	212
Distribution expenditure (capital and operating costs)	3
System security costs	-0
Gross market benefits	**999**
Transmission Network (Actionable and Future ISP Projects)	-262
Total relative market benefits	**737**

A major portion of the benefits are from avoided fixed operating and maintenance costs for offshore wind – without the augmentation, gradually increasing amounts of offshore wind capacity would be required in the Hunter Coast and Illawarra Coast REZs to supply loads in Sydney, Newcastle and Wollongong, from 500 MW by 2039-40, increasing to 2.4 GW by 2049-50. This would come in place of the more cost-effective development of an additional 2.7 GW of onshore wind and 900 MW of utility-scale solar by 2049-50 with the augmentation in place, mostly in Hunter-Central Coast. While these capacity differences are mostly equivalent on a capital cost basis, developing offshore wind is significantly more costly owing to its much greater fixed operating and maintenance costs compared to utility-scale onshore wind and solar. This is demonstrated in **Figure 40** below.

Figure 40 Annual relative market benefits of Hunter-Central Coast REZ Expansion in *Accelerated Transition* (2030-31)



Dubbo Distribution Project

	Dubbo distribution project Option 1 [DN1 Option 1]	Dubbo distribution project Option 2a [DN1 Option 2a]
EISD	December 2030	July 2031
Reported cost[84]	$607 million[85] Class 5b (±50%)	$126 million[86] Class 5b (±50%)
Cost adjusted for transmission cost escalation	$670 million (*Step Change*, 2032-33) $691 million (*Accelerated Transition*, 2032-33)	$141 million (*Step Change*, 2033-34) $146 million (*Accelerated Transition*, 2033-34)
Flow path or REZ	Dubbo Distribution REZ	Dubbo Distribution REZ
Capacity increase	700 MW	500 MW

The Dubbo distribution project supports the connection of renewable energy projects by enabling energy flows from the distribution network that service the Dubbo area into the transmission network.

[84] 'Reported cost' refers to the estimate provided by the TNSP and DNSP. 'Cost adjusted for transmission cost escalation' reflects the same estimate, restated with a common basis for transmission cost escalation, to evaluate projects at different times and across different scenarios.

[85] $607 million is the $2025 cost, which has been escalated from the $2024 proponent cost of $601 million.

[86] $126 million is the $2025 cost, which has been escalated from the $2024 proponent cost of $125 million.

Dubbo distribution project Option 1 provides 700 MW of renewable energy export capacity by upgrading and expanding the local 132 kV network around Dubbo and Wellington at a cost of $670 million in *Step Change*, while Option 2a extends Option 1 by providing an additional 500 MW of export capacity through upgrading the high-voltage transmission network at Wollar, at a cost of $141 million in *Step Change*.

Delivering these distribution projects (Options 1 and 2a) in the least-cost development path for *Accelerated Transition* allowed for development of 1.3 GW of utility-scale solar from 2031-32 and 300 MW of wind from 2034-35 in Central New South Wales.

Assessing the relative market benefits of Dubbo distribution project via TOOT analysis

This section focuses on the relative market benefits of delivering both Option 1 and 2a of the Dubbo distribution project in *Accelerated Transition* least-cost development path (CDP 3) at their respective EISDs, compared to an equivalent development path but where these two projects are not delivered at all.

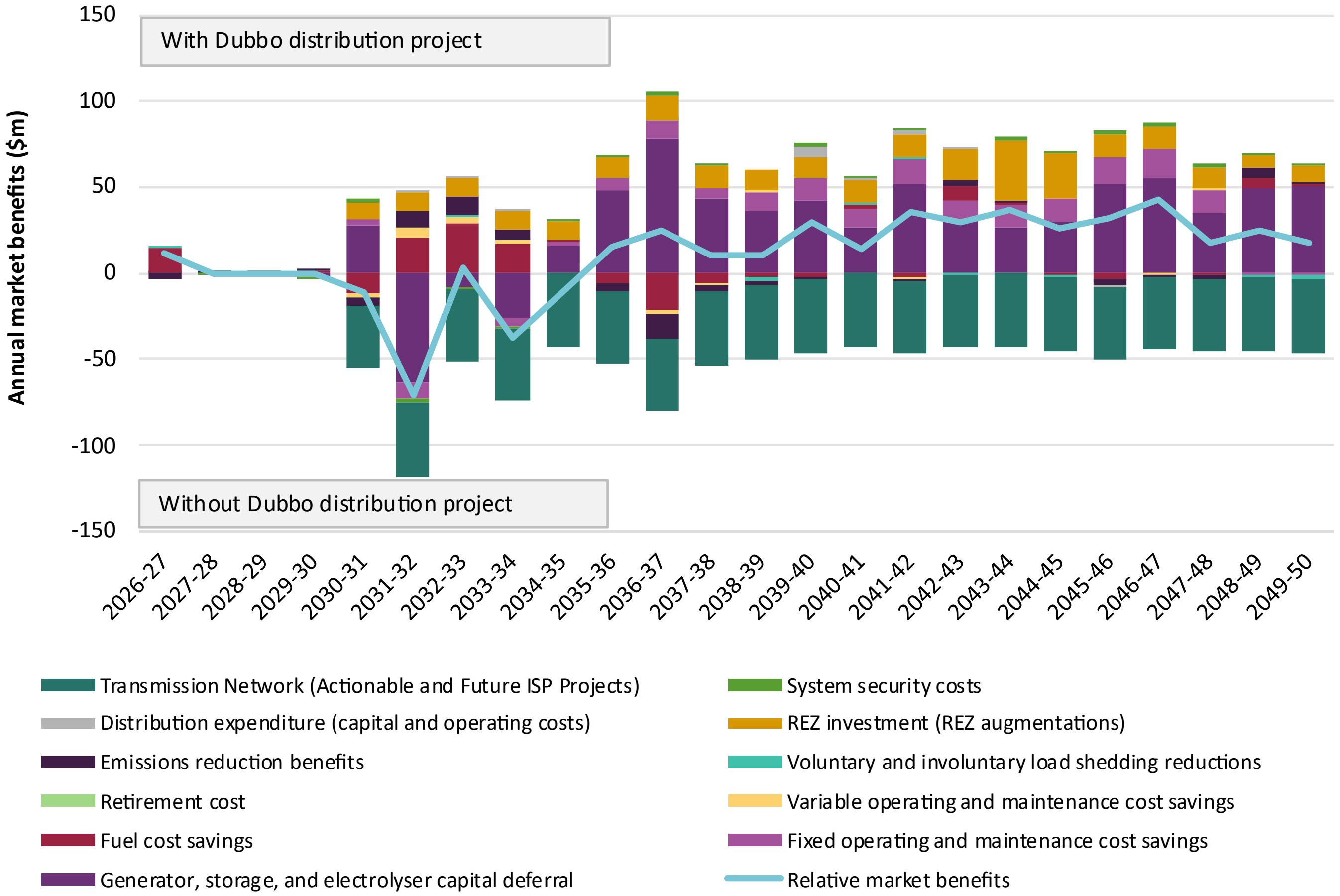
Table 70 shows that in *Accelerated Transition*, delivering Dubbo distribution project achieves relative market benefits of $42 million in the least-cost development path for *Accelerated Transition*, with the majority of benefits coming from generator and storage capital deferral and fewer associated REZ augmentations. Delivering this project defers over 700 MW of mid-scale generation and storage as well as wind in the 2030s, with less efficient developments in Northern New South Wales and Sydney, Newcastle and Wollongong replaced with utility-scale solar in Dubbo distribution REZ. It is also able to avoid some utilisation of flexible gas in the early 2030s in New South Wales, which results in fuel cost savings.

Table 70 Relative market benefits of Dubbo distribution project (Options 1 and 2a) in *Accelerated Transition* (least-cost development path)

Class of market benefit	Relative market benefit (NPV, $ million)
Generator and storage capital deferral	173
Fixed operating and maintenance cost savings	43
Fuel cost savings	30
Variable operating and maintenance cost savings	5
Retirement cost	-0
Voluntary and involuntary load shedding reductions	-0
Emissions reduction benefits	-0
REZ investment (REZ augmentations)	101
Distribution expenditure (capital and operating costs)	4
System security costs	5
Gross market benefits	**359**
Transmission Network (Actionable and Future ISP Projects)	-317
Total relative market benefits	**42**

As **Figure 41** shows, much of the benefit described above occurs in the 2040s, which suggests that this project would deliver relative market benefits if delivered at a later timing. Similar conclusions are drawn from the same analysis in *Step Change*. The project does not deliver any annualised relative market benefits in *Slower Growth*.

Figure 41 Annual relative market benefits of Dubbo distribution project (Options 1 and 2a) in *Accelerated Transition* – least-cost development path (2030-31 and 2031-32 respectively)



A6.6.6 Summarising the benefits of a coordinated approach to transmission development

Table 71 presents a comparison of the weighted net market benefits from: CDP 2 which is based on the least-cost DP under *Step Change*; CDP 4 which has the highest weighted net market benefits; and CDP 34 which has no projects delivered within their actionable windows.

Table 71 Determining the benefits of a coordinated approach to transmission development ($ billion)

CDP	*Slower Growth*	*Step Change*	*Accelerated Transition*	Weighted net market benefits
CDP 2: Least-cost Development Path in *Step Change*	9.52	29.76	42.27	27.67
CDP 4: Highest weighted net market benefit	10.29	29.55	42.55	27.85
CDP 34: No actionable projects	7.41	23.04	34.00	21.78
Relative market benefits of CDP 4 due to actionability of projects	2.87	6.50	8.55	6.07

The weighted net market benefits arising from delivering the collection of actionable transmission projects at EISD (rather than deferring all projects to their respective 'future project' timings) is $6.07 billion, highlighting the importance of progressing with the delivery of these key transmission projects in a timely manner.

This is similar, but not directly comparable, to the amount observed in the 2024 ISP of $4.92 billion (equivalent to $5.2 billion in 2025 dollars[87]).

In addition to the key changes since the Draft 2026 ISP described in Section A6.3, the increase between 2024 ISP and 2026 ISP is also due to:

- the inclusion of three more projects which deliver benefits at an actionable timing compared with the 2024 ISP, specifically Western Victoria Reinforcement program, Eastern Victoria Grid Reinforcement and Switching Station Near Wondalga, and
- an increase in length to the actionable windows of projects that were previously identified as actionable in the 2024 ISP, leading to a longer gap between an actionable timing and a non-actionable timing, which can lead to a greater impact on alternative generation and storage developments and therefore on costs incurred as a result of delay.

[87] Adjusted using a 5.7% CPI assumption consistent with the 2025 IASR.

A6.7 Step 5a: Selecting the preliminary optimal development path

This section summarises the insights from Section A6.6 and explains the reasoning that underpins the determination of the ODP. The resilience of the selected ODP to sensitivities is discussed in Section A6.8. Section A6.9 discusses the overall influence of the findings from the sensitivity analysis to the ODP selection and presents the ODP.

Table 72 shows the differences in transmission augmentations between these CDPs, and **Table 73** presents the top 10 CDPs with the highest weighted net market benefits.

Table 72 Potential actionable projects in the top-ranked CDPs by weighted net market benefits

In this CDP…		…these projects are actionable																				
CDP	Description	Central to North Queensland Reinforcement (Stage 1)	Gladstone Project	Brisbane Area 275 kV Reinforcement	Central Queensland to Southern Queensland Expansion	QNI Connect	Sydney Ring South power flow control option	Sydney Ring North (Hunter Transmission Project)	Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	Central-West Orana REZ Expansion	Switching Station near Wondalga	VNI West	Western Victoria Reinforcement program	Eastern Victoria Reinforcement Option 1	Eastern Victoria Reinforcement Option 2	Gippsland Offshore Wind Transmission Stage 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 1	Gippsland Offshore Wind Transmission Stage 2 – Phase 2	Northern Transmission Project	Project Marinus Stage 2	North West Tasmania REZ option	Central Highlands REZ option
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)		✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	✓	✓				✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	✓	✓	✓			✓	✓	✓	✓		✓	✓			✓	✓	✓		✓	✓	
CDP 14	CDP 4 without actionable Central-West Orana REZ Expansion	✓	✓	✓			✓	✓	✓		✓	✓	✓			✓	✓	✓		✓	✓	
CDP 27	CDP 4 with actionable Central Highlands REZ option	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	✓
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓	
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓		✓		✓	✓	
CDP 25	CDP 4 without actionable North West Tasmania REZ option	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓		
CDP 3	Least-cost DP for *Accelerated Transition*	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓	✓	✓

Table 73 Top 10 candidate development paths across scenarios (in $ billion) – in order of descending weighted net market benefits

CDP	*Description*	*Slower Growth*	*Step Change*	*Accelerated Transition*	WNMB	Rank based on WNMB	Worst weighted regrets	Rank based on WWR
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	10.29	29.55	42.55	27.86	1	0.14	5
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	10.30	29.58	42.47	27.85	2	0.14	3
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	10.29	29.54	42.53	27.85	3	0.14	6
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	10.30	29.52	42.50	27.84	4	0.14	1
CDP 14	CDP 4 without actionable Central-West Orana REZ Expansion	10.43	29.43	42.52	27.83	5	0.16	9
CDP 27	CDP 4 with actionable Central Highlands REZ option	10.25	29.50	42.56	27.83	6	0.15	7
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	10.20	29.54	42.55	27.83	7	0.16	10
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	10.30	29.50	42.51	27.83	8	0.14	2
CDP 25	CDP 4 without actionable North West Tasmania REZ option	10.29	29.50	42.50	27.82	9	0.14	4
CDP 3	Least-cost DP for *Accelerated Transition*	9.97	29.49	42.71	27.79	10	0.23	14

The selection of the ODP needs to consider not just the weighted net market benefits of each CDP, but also the relative differences in net market benefits between them, their performance across scenarios to balance under- and over-investment risks, their worst weighted regrets, and the drivers of their benefits and regrets.

Section A6.6.3 discussed the cost and benefits of each project across the scenario collection and highlighted how all projects in CDP 4 provide an increase in weighted net market benefits when delivered at an actionable timing as opposed to delivery beyond their actionable windows. These projects collectively provide significant benefits across scenarios, support emission reductions, and allow for the efficient sharing of VRE across the NEM.

CDP 5 and CDP 7 are ranked second- and third-best in weighted net market benefits, with close proximity in market benefits and weighted regret to CDP 4. The top three CDPs also perform relatively similarly for *Step Change (*ranking fifth-best for CDP 4, fourth-best for CDP 5 and seventh-best for CDP 7), and average in *Slower Growth* (ranking sixteenth, thirteenth, and seventeenth-best). In *Accelerated Transition*, CDP 4 and CDP 7 perform similarly well (ranked third- and fifth-best), while CDP 5 is ranked considerably worse (eleventh-best).

CDPs that perform better in *Slower Growth* compared to CDP 4 feature several projects deferred to outside their actionable windows, given the slower pace of change delays the investment need. In *Step Change*, only its least-cost DP, as well as CDPs where Project Marinus Stage 2, or Central to North Queensland Reinforcement (Stage 1) are not delivered at an actionable timing perform better than CDP 4. Finally, in *Accelerated Transition,* only its least-cost DP, and the CDP that includes the delivery of Central Highlands REZ option at an actionable timing rank higher.

CDP 4 is ranked fifth on a worst weighted regret basis, driven by the risk of over-investment in *Slower Growth*, which features risk of industrial load closures and lower demand growth which can reduce the value of some transmission developments in this scenario, though the relative difference in regret between these CDPs is very low.

Based on the assessment of the relative merits of each CDP, AEMO selects CDP 4 as the preliminary optimal development path, as it delivers the highest weighted net market benefits, has well-balanced benefits across all scenarios, and ranks high on the worst weighted regret basis.

To select the final ODP, further analysis of the resilience of CDP 4 against key additional uncertainties through sensitivity testing is provided in Section A6.8.

A6.8 Step 5b: Sensitivity analysis to test resilience of candidate development paths

This section outlines the resilience of the CDPs' identified market benefits to changes in input assumptions used in the scenario analysis. The discussion in this sub-section generally focuses on a select group of CDPs that delivered the highest weighted net market benefits to provide further information to assist the identification and validation of the preliminary ODP. The sensitivity analysis in this section is focused on sensitivities to *Step Change*.

The impact of these sensitivities on generation and storage capacity development is explored in Appendix A2, while Appendix A9 also explores the impact of various demand side factor uncertainties. The capacity developments, cost-benefit, and emissions outcomes of the scenarios, and the sensitivities, are provided in the Generation and Storage Outlook Workbooks.

The sensitivities explored in this 2026 ISP Appendix A6 focus on the robustness of the preliminary ODP selection by testing the impact of CDP 4 in *Step Change* if:

- various circumstances delay the delivery of infrastructure development in the next decade, such as through constrained supply chains, need for social licence, challenges with planning approvals or construction, affecting the development limits of generation, storage, and network developments,
- higher energy consumption from data centres and large industrial loads was to eventuate compared to what was forecast under *Step Change,*
- the level of overall CER coordination in the outlook period, including V2G and VPP, was to not exceed June 2025 levels (such that there was no growth in uptake of coordination), and
- energy efficiency improvements were to slow down or speed up compared with what was assumed in *Step Change*.

A6.8.1 *Constrained Delivery*

AEMO has explored a *Constrained Delivery* sensitivity analysis to see whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission as well as generation and storage projects were unable to be delivered at the pace required. There may be many reasons for delivery delays – through planning approvals and the need for social licence, the supply chain, or construction – but the sensitivity only limited the rate of build, not what determined the delays.

Key assumption changes in this sensitivity are:

- NEM-wide technology-specific annual build limits are imposed on future wind, utility-scale solar, and utility-scale storages until 2034-35, see **Figure 42**. The limits are approximated by assuming a slower development of projects in the connections pipeline, with different capacity reductions assumed at various stages of the pipeline[88] to capture potential delivery delays or project cancellations for the reasons listed above. The amount of new capacity expected to come online following these reductions is smoothed to produce a steadily increasing trajectory over time, reflecting the

[88] The build limits assume a 20% reduction in capacity for projects in the application stage where the performance of the plant "as designed" is assessed, and a 10% reduction for projects in the proponent implementation stage, which is when the proponent and the network service provider (NSP) execute the connection agreement, the NSP constructs the network interface, and the proponent constructs the plant and prepares registration application. This stage is considered complete when the registration package is submitted to AEMO.

expectation that pressures on infrastructure delivery will progressively ease. The delivery of committed, anticipated, and policy-supported projects as well as generic new entrant projects are assumed to be impacted by the same set of development and delivery conditions. Therefore, these delivery constraints are applied equally on all types of generation and storage projects. The impact of these limits is presented in **Figure 43** below.

- Delays to the EISD for flow path and REZ network augmentation options of up to three years (including committed and anticipated projects) were assumed to test impact if industry is unable to build capability to deliver above recent transmission line build rates. It was assumed that committed projects would be delayed six months, anticipated projects 12 months, and actionable projects an average of two years. These assumptions were set to allow a 5% year-on-year increase from recent transmission line build history (approximately 365 km/year during the construction of Stage 1 of Project EnergyConnect and Eyre Peninsula Link).
- Offshore wind projects are also impacted by the development constraints delaying the development trajectory to deliver 9 GW of capacity by three years.
- The cost of generation, storage and transmission rises as result of delivery delays, on average by 30% during this period of heightened limitation until 2034-35, calculated using the uncertainty band in technology costs from the CSIRO's *2025-26 GenCost Consultation Draft report*[89]. There may be many reasons for that rise – competing for skills and equipment as global demand rises, the delays themselves, more costly conditions to meet planning requirements – but the sensitivity modelled the risk in cost only.

Figure 42 shows the NEM's annual build capability for utility-scale solar, wind, and utility-scale storage assumed in the *Constrained Delivery* sensitivity, relative to *Step Change*.

[89] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

Figure 42 ***Constrained Delivery*** **annual build to 2034-35 considering build limits influenced by historical commissioning rate for onshore wind, utility-scale solar generation and battery storage devices (GW)**

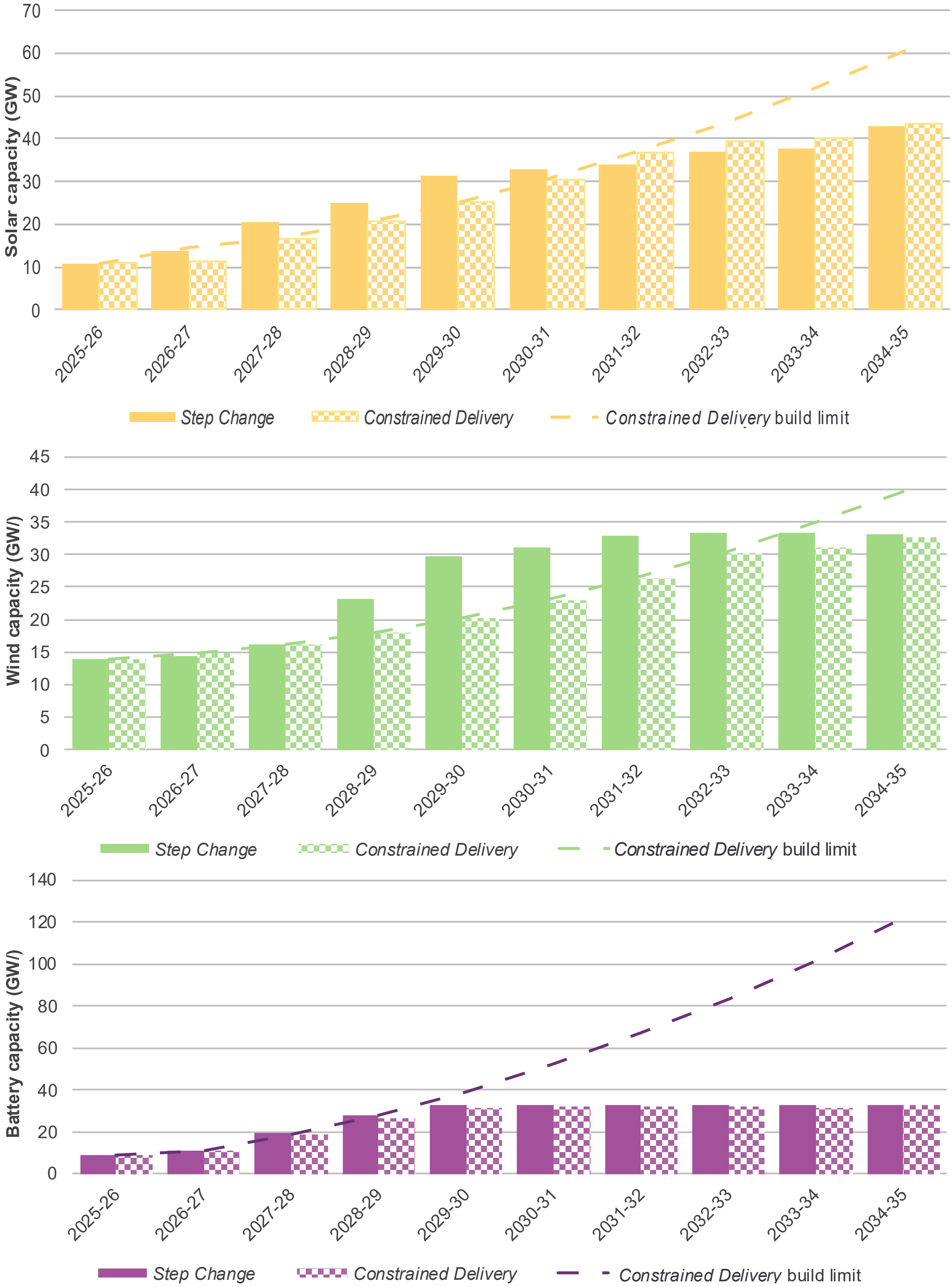
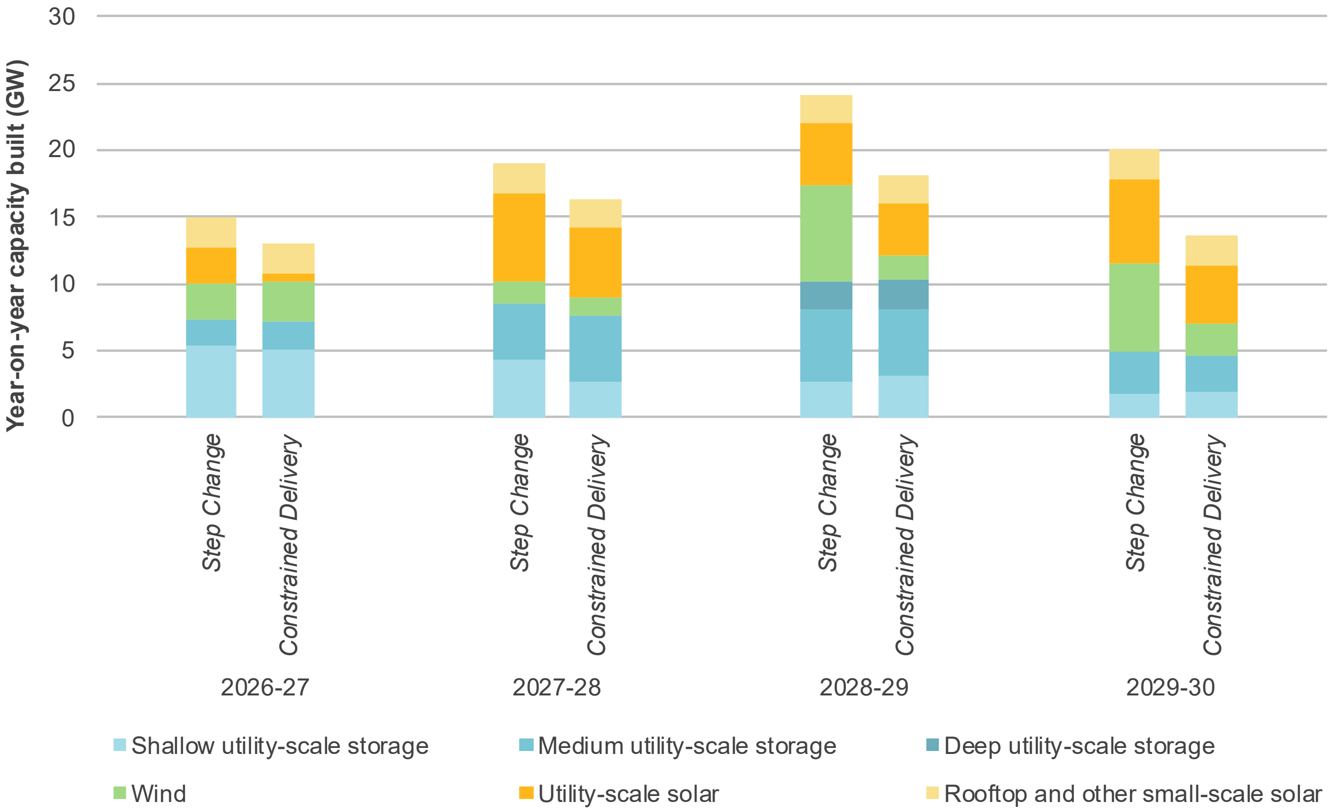


Figure 43 presents the renewable annual build capacities in both *Step Change* and the *Constrained Delivery* sensitivity over the period to 2029-30, highlighting the lower levels of additional builds limits (particularly of utility-scale solar and wind) in the short to medium term in the sensitivity (observed by the step down in the column of data for the sensitivity). While development increases each year of 2026-27, 2027-28 and 2028-29, development slows in 2029-30 as much of the storage capacity sought in the sensitivity is either committed or anticipated, and therefore is developed in the earlier years, rather than lower build limits. More details can be found in Section A2.4.1 in Appendix A2.

Figure 43 NEM renewable annual build capacities, *Step Change* versus *Constrained Delivery* sensitivity, 2026-27 to 2029-30 (GW)



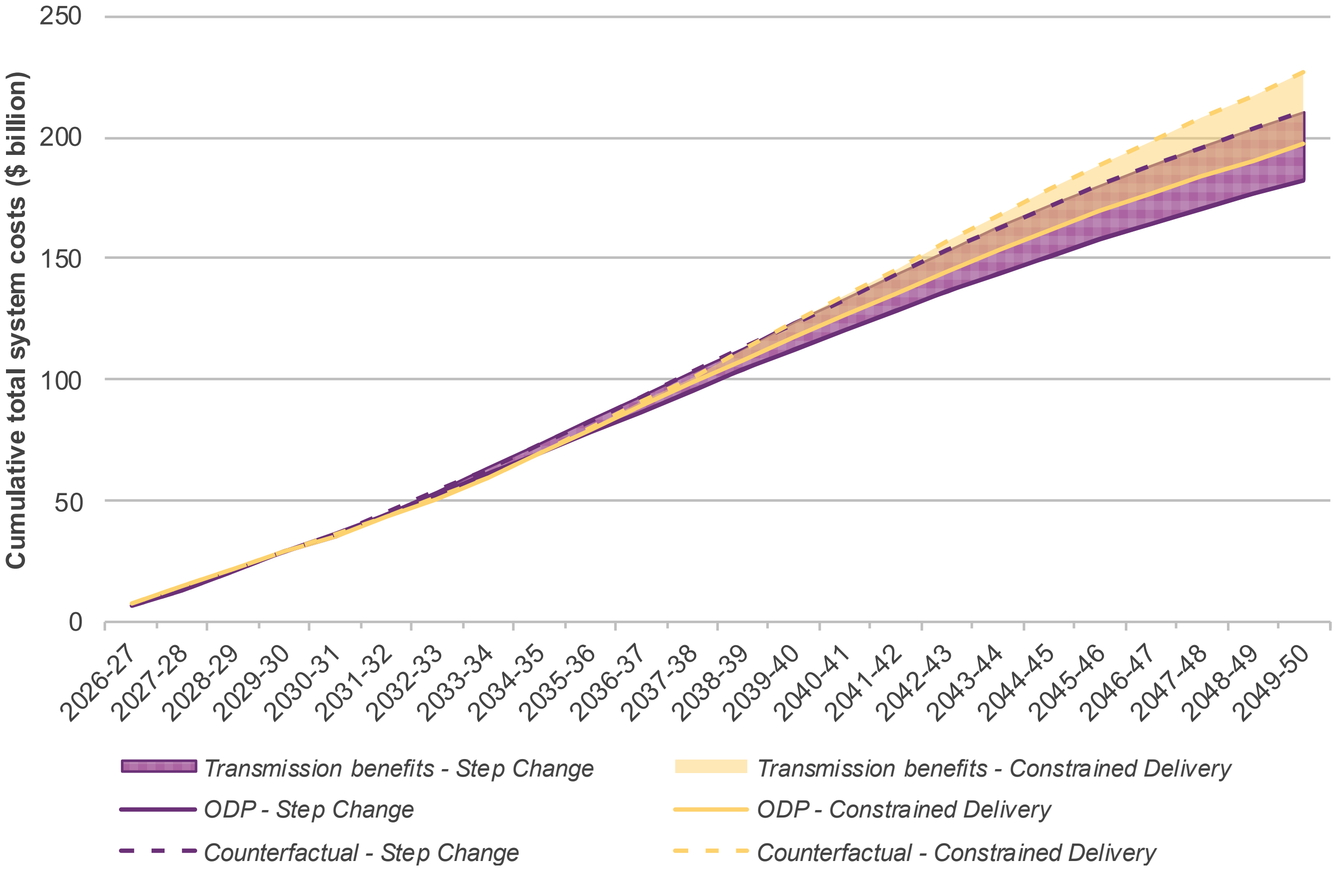
The delay applied to EISDs means that the transmission projects (including committed and anticipated projects) in this sensitivity, are delivered later than those in the corresponding CDPs in *Step Change*. Actionable windows for each project have also been shifted accordingly to reflect that projects would still need to commence now, to meet the delayed EISDs.

The net market benefits of the ODP (CDP 4) in the *Constrained Delivery* sensitivity are presented below in **Table 74**, alongside the *Step Change* results discussed in Section A6.7.

The *Constrained Delivery* sensitivity shows that progressing transmission developments provides value in mitigating risks associated with delivery delays, and is of greater value if generation, storage and transmission projects themselves are affected by delivery delays, and cost increases. When fewer projects proceed, and those that do are more expensive, it becomes increasingly important to ensure that available investments can access the best resource locations and network capacity.

Consistent with this, if the delivery of generation, storage, and transmission is slowed due to these development and delivery constraints then the net market benefits of the preliminary ODP (CDP 4) increases by around $5.2 billion relative to how much net market benefits it provides in *Step Change*. This reflects the greater role of transmission assets in enabling efficient use of delivered assets in a constrained development environment. This does not mean that delivery should be slowed – even though transmission is more valuable in this sensitivity, that additional value only partially offsets the significantly higher costs of delivery constraints, as shown in **Figure 44**.

Figure 44 Consumer benefits of transmission, *Step Change* versus *Constrained Delivery*



Under *Constrained Delivery*, the system has a reduced ability to access and efficiently use geographically diverse renewable generation compared to *Step Change*. This impact is most pronounced in the 'no transmission' counterfactual DP, which becomes more reliant on local supply and results in higher coal-fired and gas-powered generation in the early years of the outlook.

The preliminary ODP mitigates these effects by improving access to geographically dispersed renewable generation and storage, even when overall development is delayed. As a result, both the emissions reduction benefit and capital deferral benefit of the preliminary ODP are larger than the value in *Step Change*.

This result does not indicate that total system costs are lower under *Constrained Delivery* – rather, total system costs are $16.5 billion higher compared to *Step Change. In Constrained* Delivery, transmission provides a benefit of $34.8 billion, which is $5.2 billion higher than the benefit it provides in *Step Change*.

Under these conditions, policy outcomes – such as renewable energy development and emissions reduction objectives – are delayed, but catch up as projects are delivered. For example, renewable energy reaches around 75% by 2030, below the

82% Powering Australia Plan target, which is instead met in 2032. The NEM's contribution to the 2030 emissions target is also lower in the near term, exceeding its allocated share by around 6.5 million tonnes of carbon dioxide equivalent.

Table 74 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *Constrained Delivery* sensitivity ($ million)

Class of market benefit	*Step Change*	*Constrained Delivery* sensitivity	Difference
Generator, storage, and electrolyser capital deferral	23,319	27,440	4,122
Fixed operating and maintenance cost savings	3,817	6,241	2,424
Fuel cost savings	9,488	5,285	-4,203
Variable operating and maintenance cost savings	601	390	-211
Retirement cost	142	140	-2
Voluntary and involuntary load shedding reductions	163	148	-15
Emissions reduction benefits	16	3,616	3,600
REZ investment (REZ augmentations)	-97	-333	-236
Distribution expenditure (capital and operating costs)	130	69	-61
System security costs	375	465	90
Gross market benefits	**37,953**	**43,461**	**5,508**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,698	-291
Total net market benefits	**29,546**	**34,764**	**5,217**

Table 75 presents the net market benefits and rankings of key CDPs in the *Constrained Delivery* sensitivity alongside *Step Change*. Results show increased value from earlier and more extensive network development. CDPs with a higher proportion of actionable transmission projects perform better, reflecting the system value of earlier access to stronger network connections when generation and storage delivery is delayed.

For example, CDP 3, which includes the largest number of actionable projects in the CDP collection, improves from ninth ranking under the scenario assumptions (from the selected CDPs tested) to the highest ranked CDP in this sensitivity on a weighted net markets benefits basis, if the *Constrained Delivery* sensitivity were to replace *Step Change* in the scenario collection[90].

In contrast, CDPs with fewer actionable projects – including CDP 5, CDP 7 and CDP 21 – perform relatively worse.

Taken together, these results demonstrate that transmission provides increased consumer value under constrained delivery conditions. Improved access to high-quality renewable resources and more efficient dispatch across regions reduces near-term supply and emissions risks and supports faster convergence to policy targets as constraints ease. The preliminary ODP (CDP 4) remains robust under delivery uncertainty, and progressing the actionable projects in CDP4 provides a material hedge against delays by preserving system flexibility and reducing the impact of slower generation and storage development.

[90] That is, if the assumptions for *Accelerated Transition* and *Slower Growth* were unchanged, and the delivery limitations affect only *Step Change*.

Table 75 Net market benefits and weighted net market benefits for key CDPs (in $ billion), core scenario outcomes and *Constrained Delivery* sensitivity

		Core scenario outcomes				*Constrained Delivery*			
CDP	**Description**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	11	27.79	9	35.04	1	30.34	1
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	4	27.86	1	34.76	4	30.26	2
CDP 25	CDP 4 without actionable North West Tasmania REZ option	29.50	9	27.82	8	34.78	2	30.25	3
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	7	27.84	4	34.77	3	30.25	4
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	5	27.83	6	34.76	5	30.23	5
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	3	27.85	2	34.74	6	30.23	6
CDP 27	CDP 4 with actionable Central Highlands REZ option	29.50	8	27.83	5	34.71	8	30.23	7
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	6	27.85	3	34.64	11	30.20	8
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	14	27.77	10	34.59	12	30.18	9
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	29.47	13	27.78	9	34.69	9	30.18	10
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	29.50	10	27.83	7	34.48	14	30.12	11
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	29.48	12	27.68	11	34.74	7	30.10	12
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	12	34.67	10	29.93	13
CDP 24	CDP 4 without actionable Project Marinus Stage 2	29.66	2	27.62	13	34.55	13	29.87	14
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	15	27.36	15	27.36	15	29.78	15
CDP 8	CDP 4 with actionable Auburn River Switching Station and Central Queensland to Southern Queensland Expansion	28.18	16	26.58	17	26.58	16	29.01	16
CDP 1	Least-cost DP for *Slower Growth*	28.07	17	26.84	16	26.84	17	28.78	17

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

A6.8.2 *Higher Demand*

Based on *Step Change*, the *Higher Demand* sensitivity features a very high assumption around industrial development and data centre load growth. This sensitivity has been developed in response to stakeholder feedback received on the Draft

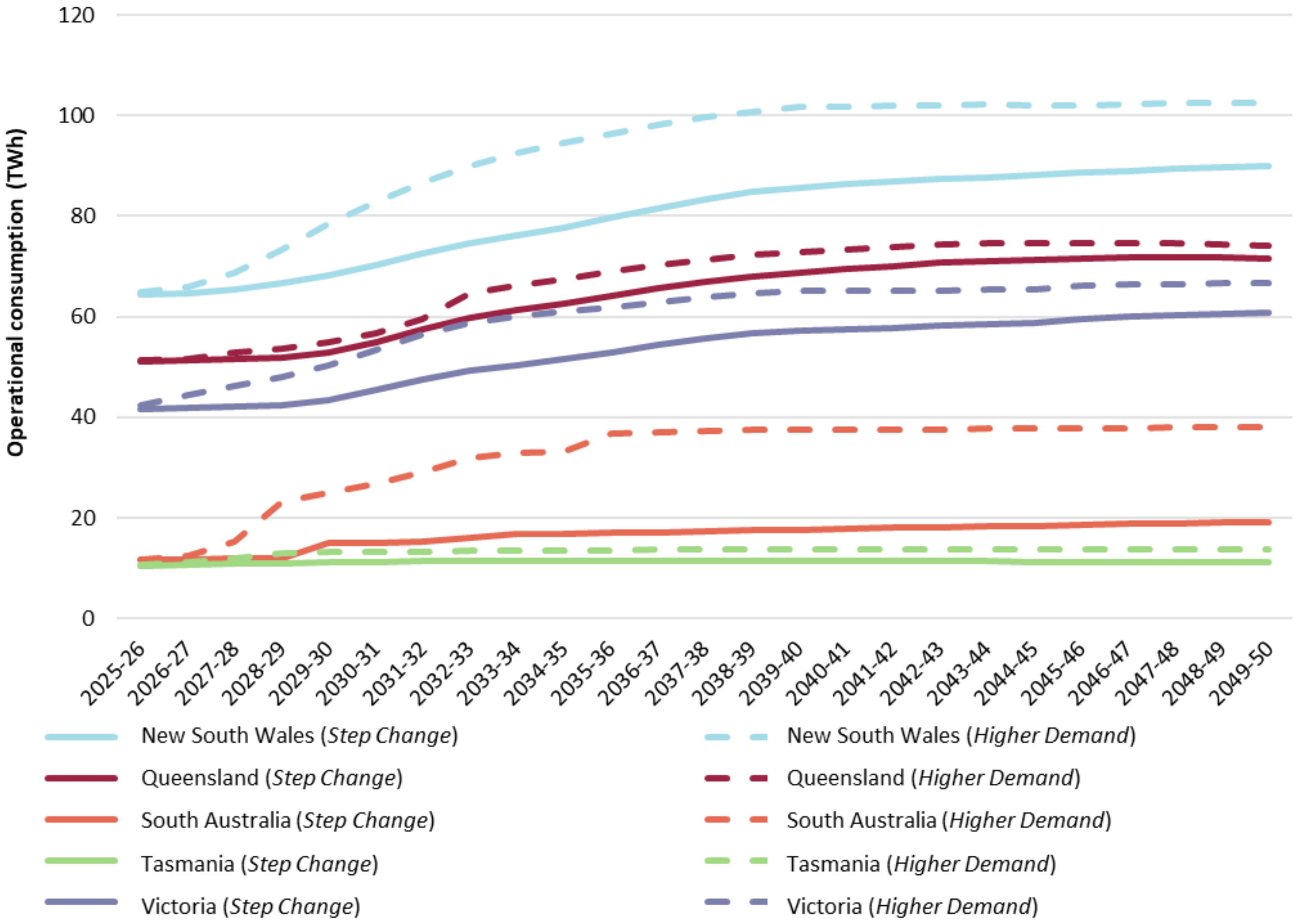
2026 ISP, and tests implications on development needs under high demand growth noting that there has been much interest in data centre development in recent months. It includes additional loads from known large industrial load (LIL) and data centre projects in the pipeline to reflect the potential growth above the *Step Change* forecast[91]. Specific modifications from the assumptions made in *Step Change* are:

- all prospective large industrial loads indicated as committed or anticipated, as well as those named in feedback to the Draft 2026 ISP, were included at the connection date provided by NSPs,
- all prospective data centres indicated as committed or anticipated, as well as those named in feedback to the Draft 2026 ISP were included, but applying a 50% project realisation factor to recognise ongoing digital load uncertainty (this reflects strong growth in the first 10 years of the forecast, with the longer-term growth trajectory reflecting a similar growth trend as *Step Change*),
- existing large industrial loads and data centres operate according to the *Accelerated Transition*, reflecting strong economic conditions, high utilisation of existing data centres and ambitious electrification of industry, and
- other business and residential consumption is as per *Step Change*.

Figure 45 presents the load growth in *Step Change* and in this sensitivity. South Australia and New South Wales see the largest increase in load over the short to medium term, followed by Victoria. Compared to *Accelerated Transition,* energy consumption grows faster in this sensitivity over the short to medium term, but consumption grows at a faster rate in *Accelerated Transition* during the mid-2030s, resulting in higher demands in the scenario from that point onwards.

[91] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal.

Figure 45 Impact of *Higher Demand* on operational consumption (TWh)



As shown in **Table 76,** the sensitivity results in significantly higher net market benefits for CDP4 compared with those found in *Step Change*. Transmission delivers more significant savings, avoiding around $14 billion in generator, storage and electrolyser capital costs, and $15 billion in fuel costs relative to *Step Change*. Under the sensitivity the 'no transmission' counterfactual DP is a much greater cost given the relatively high short- to medium-term load growth (higher than in *Accelerated Transition*). This requires significant flexible gas with CCS in the counterfactual from 2033-34 onwards, compared to *Step Change.*

Table 76 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *Higher Demand* sensitivity ($ million)

Class of market benefit	*Step Change*	*Higher Demand* sensitivity	Difference
Generator, storage, and electrolyser capital deferral	23,319	37,538	14,219
Fixed operating and maintenance cost savings	3,817	5,111	1,294
Fuel cost savings	9,488	24,553	15,065
Variable operating and maintenance cost savings	601	1,663	1,062
Retirement cost	142	176	34
Voluntary and involuntary load shedding reductions	163	371	208
Emissions reduction benefits	16	20	4
REZ investment (REZ augmentations)	-97	-658	-561
Distribution expenditure (capital and operating costs)	130	96	-34
System security costs	375	50	-325
Gross market benefits	**37,953**	**68,920**	**30,967**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,407	0
Total net market benefits	**29,546**	**60,513**	**30,967**

Table 77 presents the net market benefits of selected CDPs in the sensitivity and across the scenario collection. The higher load growth in the short to medium term increases the overall value of transmission augmentation, as seen by the significant increase in net market benefits of the CDPs (from around $27 billion in *Step Change* to around $60 billion in the sensitivity).

The higher growth in this sensitivity has resulted in the top-ranked CDP in this sensitivity on a weighted net market basis (if this sensitivity were to replace *Step Change* in the weighted cost benefit analysis) becoming CDP 3 – the least-cost DP for *Accelerated Transition*. CDP 4, ranked first on a weighted net market benefits basis across the scenarios, would be ranked second in both the sensitivity and on a weighted net market benefits basis.

In the sensitivity, Central to North Queensland Reinforcement (Stage 1) would be beneficial at an actionable timing, allowing additional solar and wind capacity to be developed in Northern Queensland (800 MW altogether by 2032-33), and deferring VRE builds in the rest of Queensland and Northern New South Wales. Other projects – such as Northern Transmission Project, QNI Connect, North West Tasmania REZ option, Brisbane Area 275 kV Reinforcement, and the Switching Station near Wondalga project – see increased benefits relative to *Step Change*.

Table 77 Net market benefits and weighted net market benefits for key CDPs (in $ billion), core scenario outcomes and *Higher Demand* sensitivity

		Core scenario outcomes				*Higher Demand* sensitivity			
CDP	Description	*Step Change*	*Step Change* rank	WNMB	WNMB rank	*Step Change*	*Step Change* rank	WNMB	WNMB rank
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	10	27.79	9	60.73	1	42.16	1
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	3	27.86	1	60.51	2	42.10	2
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	5	27.85	3	60.47	6	42.08	3
CDP 27	CDP 4 with actionable Central Highlands REZ option	29.50	7	27.83	5	60.46	7	42.07	4
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	6	27.84	4	60.47	5	42.07	5
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	2	27.85	2	60.49	4	42.07	6
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	4	27.83	6	60.49	3	42.07	7
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	11	27.77	10	60.42	8	42.06	8
CDP 21	CDP 4 without actionable Gippsland Offshore Wind Transmission Stage 2 – Phase 1	29.50	9	27.83	7	60.34	9	42.01	9
CDP 25	CDP 4 without actionable North West Tasmania REZ option	29.50	8	27.82	8	60.27	10	41.98	10
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	12	27.36	12	60.04	12	41.64	11
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	11	60.13	11	41.64	12
CDP 1	Least-cost DP for *Slower Growth*	28.07	13	26.84	13	54.29	13	38.91	13

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

A6.8.3 Consumer energy resource coordination

There is uncertainty about how CER coordination – through consumer VPPs and V2G charging – will shape the future of the NEM. These sensitivities assessed the impact of different levels of coordination of CER storages on the ODP in *Step Change*. There are two variations to this assumption, with all other inputs aligned with *Step Change*:

- *No Further VPP Uptake*, which assumed that no additional customers choose to coordinate their batteries via VPP's, meaning that all additional CER battery uptake is assumed to be uncoordinated, and
- *No Further CER Coordination*, which assumed that no additional coordination is selected by either home battery or vehicle owners, meaning that all additional CER battery uptake and vehicle charging was assumed to be uncoordinated.

The sensitivity therefore isolated the ratio of passive CER storage to coordinated CER storage between the sensitivities. Appendix A9 has more information on the inputs of this sensitivity.

No Further VPP Uptake

Without the forecast level of coordination provided by VPPs, and with that battery uptake instead being uncoordinated, higher levels of medium-duration utility-scale storages would be required and flexible gas generation must be further built and utilised in the 2040s to reliably meet forecast energy consumption, resulting in higher total system costs by $3.8 billion[92, 93] for CDP 4. Additionally, the net market benefits of CDP 4 (against the 'no transmission' counterfactual DP) in this sensitivity increase by $1.23 billion compared with the net market benefits of CDP 4 relative to the counterfactual in *Step Change*; see **Table 78** below.

With lower levels of VPP uptake (resulting in lesser coordination, rather than lesser battery storages), there is reduced capacity that would be expected to explicitly firm the reliability of the power system. To offset the reduced coordination, greater utility-scale generation and storage developments would be required, which is greater still in the 'no transmission' counterfactual where the ability for peak capacity sharing between regions is reduced.

This sensitivity analysis highlights the benefits of coordination of consumer-owned assets. While total system costs increase with lower VPP uptake (that is, with lower battery coordination), as **Table 78** shows, the cost relationship between the CDPs is relatively minimal. The impacts on the generation and storage developments required without the forecast VPP uptake are relatively similar across CDPs and the counterfactual (see Appendix A2 and **Table 79**). The CDPs therefore remain relatively robust in terms of rankings, with CDP 4 still the highest ranked.

Table 78 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *No Further VPP Uptake* sensitivity ($ million)

Class of market benefit	*Step Change*	*No Further VPP Uptake* sensitivity	Difference
Generator, storage, and electrolyser capital deferral	23,319	24,355	1,036
Fixed operating and maintenance cost savings	3,817	4,015	198
Fuel cost savings	9,488	9,439	-49
Variable operating and maintenance cost savings	601	602	1
Retirement cost	142	152	10
Voluntary and involuntary load shedding reductions	163	162	-1
Emissions reduction benefits	16	14	-2
REZ investment (REZ augmentations)	-97	-109	-13
Distribution expenditure (capital and operating costs)	130	117	-13
System security costs	375	440	65
Gross market benefits	**37,953**	**39,187**	**1,233**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,407	0
Total net market benefits	**29,546**	**30,780**	**1,233**

[92] This contrasts the analysis presented in the table below, which demonstrates the change in the value of transmission from this sensitivity.

[93] More information is available in Appendix 9.

Table 79 Net market benefits and weighted net market benefits for key CDPs (in $ billion), core scenario outcomes and *No Further VPP Uptake* sensitivity

		Core scenario outcomes				*No Further VPP Uptake* sensitivity			
CDP	**Description**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	5	27.86	1	30.78	5	28.42	1
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	4	27.85	2	30.81	4	28.42	2
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	7	27.85	3	30.77	7	28.42	3
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	8	27.84	4	30.76	8	28.41	4
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	6	27.83	5	30.78	6	28.40	5
CDP 25	CDP 4 without actionable North West Tasmania REZ option	29.50	9	27.82	6	30.73	9	28.39	6
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	13	27.77	9	30.65	13	28.37	7
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	10	27.79	7	30.72	10	28.35	8
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	29.47	12	27.78	8	30.71	12	28.35	9
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	29.48	11	27.68	10	30.71	11	28.25	10
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	29.33	14	27.67	11	30.55	14	28.23	11
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	12	30.98	1	28.23	12
CDP 24	CDP 4 without actionable Project Marinus Stage 2	29.66	2	27.62	13	30.86	2	28.18	13
CDP 26	CDP 4 without actionable North West Tasmania REZ option and actionable Project Marinus Stage 2	29.64	3	27.60	14	30.84	3	28.16	14
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	15	27.36	15	30.31	15	27.97	15
CDP 1	Least-cost DP for *Slower Growth*	28.07	16	26.84	16	29.34	16	27.43	16
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 KV option (Stage 1 and Stage 2)	24.58	17	24.40	17	25.09	17	24.63	17

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

No Further CER Coordination

This sensitivity examined the impact of reduced CER coordination, through both VPPs and V2Gs, on the investment needs of the NEM. In this sensitivity, CER uptake that was forecast to be coordinated in *Step Change* was instead assumed to act as a passive device operated to meet households' needs rather than coordinated to potentially support system needs as well.

If no additional coordination beyond current levels were applied, total system costs would increase by $5.2 billion[94, 95] in CDP 4, with higher levels of medium-duration utility-scale storages and higher flexible gas generation needed particularly in the 2040s to meet consumer needs. Additionally, the net market benefits of CDP 4 (against the 'no transmission' counterfactual DP) in this sensitivity increase by $1.84 billion compared with the net market benefits of CDP 4 relative to the counterfactual in *Step Change*; see **Table 80**.

Similar to the findings in the *No Further VPP Uptake* sensitivity, with lower levels of coordination of CER storages, there is less assumed contribution from CER developments that would more-effectively firm the reliability of the power system. To offset the reduced coordination, greater utility-scale generation and storage developments would be required, which is greater still in the 'no transmission' counterfactual where the ability for peak capacity sharing between regions is reduced. This sensitivity also demonstrates the even greater benefits of overall coordination of consumer-owned assets, including both VPPs and V2G vehicles.

Table 80 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *No Further CER Coordination* sensitivity ($ million)

Class of market benefit	*Step Change*	*No Further CER Coordination* sensitivity	Difference
Generator, storage, and electrolyser capital deferral	23,319	24,853	1,535
Fixed operating and maintenance cost savings	3,817	4,157	341
Fuel cost savings	9,488	9,440	-47
Variable operating and maintenance cost savings	601	596	-5
Retirement cost	142	144	2
Voluntary and involuntary load shedding reductions	163	136	-27
Emissions reduction benefits	16	15	-1
REZ investment (REZ augmentations)	-97	-118	-21
Distribution expenditure (capital and operating costs)	130	116	-13
System security costs	375	450	75
Gross market benefits	**37,953**	**39,791**	**1,837**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,407	0
Total net market benefits	**29,546**	**31,384**	**1,837**

As **Table 81** shows, the impact on weighted net market benefits of the CDPs is relatively minimal, with similar generation and storage impacts across the CDPs and the counterfactual (see Appendix A2). The CDPs therefore remain relatively robust in terms of rankings, with CDP 4 still the highest ranked.

[94] This contrasts the analysis presented in the table below, which demonstrates the change in the value of transmission from this sensitivity.

[95] More information is available in Appendix A9.

Table 81 Net market benefits and weighted net market benefits for key CDPs (in $ billion), core scenario outcomes assumptions and *No Further CER Coordination* sensitivity

		Core scenario outcomes				*No Further CER Coordination* sensitivity			
CDP	Description	*Step Change*	*Step Change* rank	WNMB	WNMB rank	*Step Change*	*Step Change* rank	WNMB	WNMB rank
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	5	27.86	1	31.38	5	28.70	1
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	4	27.85	2	31.42	4	28.70	2
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	7	27.85	3	31.38	7	28.70	3
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	8	27.84	4	31.37	8	28.68	4
CDP 27	CDP 4 with actionable Central Highlands REZ option	29.50	9	27.83	5	31.34	9	28.68	5
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	6	27.83	6	31.38	6	28.68	6
CDP 25	CDP 4 without actionable North West Tasmania REZ option	29.50	10	27.82	7	31.33	10	28.67	7
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	14	27.77	10	31.26	14	28.65	8
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	11	27.79	8	31.33	11	28.64	9
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	29.47	13	27.78	9	31.32	13	28.63	10
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	29.48	12	27.68	11	31.32	12	28.53	11
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	29.33	15	27.67	12	31.16	15	28.52	12
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	13	31.51	1	28.48	13
CDP 24	CDP 4 without actionable Project Marinus Stage 2	29.66	2	27.62	14	31.46	2	28.45	14
CDP 26	CDP 4 without actionable North West Tasmania REZ option and actionable Project Marinus Stage 2	29.64	3	27.60	15	31.43	3	28.43	15
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	16	27.36	16	30.84	16	28.21	16
CDP 1	Least-cost DP for *Slower Growth*	28.07	17	26.84	17	30.02	17	27.74	17
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	24.58	18	24.40	18	25.96	18	25.03	18

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

A6.8.4 Energy efficiency

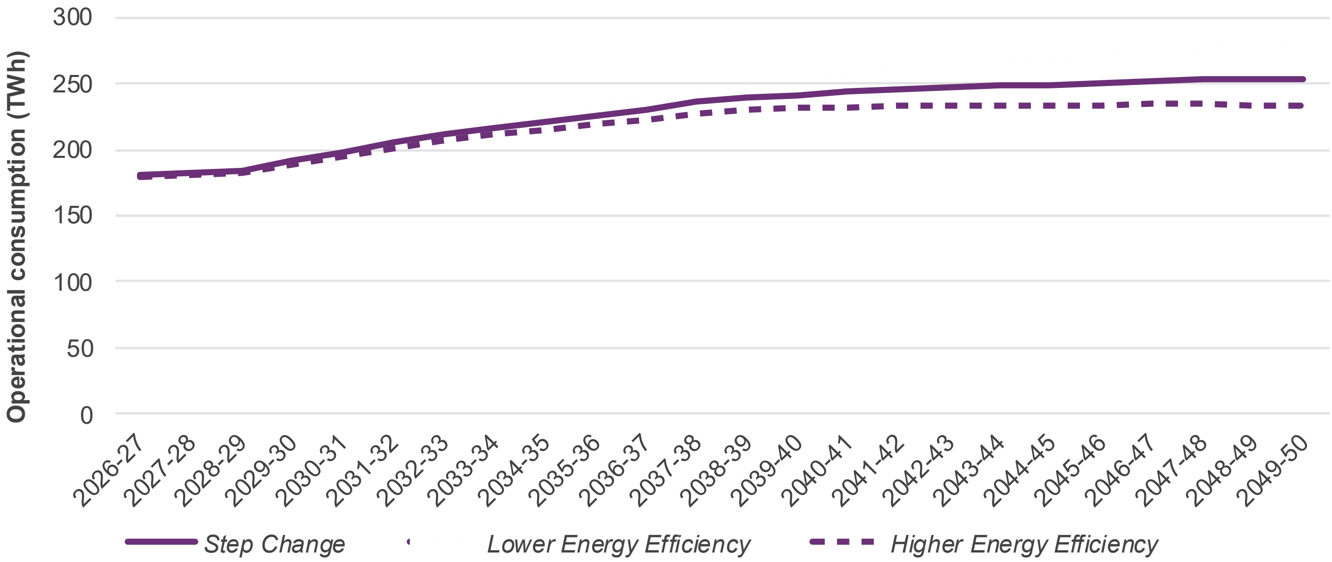
The energy efficiency sensitivities examined the effect of customers varying their investment in devices that reduce their electrical usage or improve their building thermal performance to reduce heating and cooling needs. Much of the energy efficiency investments made by consumers (residential, business and industry) are anticipated through technology improvements and building improvements, made by economic choices or supported by policy. The sensitivity was compared with *Step Change* with two variations:

- *Lower Energy Efficiency* – which examines reduced customer investment in energy efficiency, categorised by increasing the forecast consumption of electricity compared to *Step Change*, and
- *Higher Energy Efficiency* – which examines increased customer investment in energy efficiency, categorised by reducing the forecast consumption of electricity compared to *Step Change*.

This sensitivity limited energy efficiency investments to only those that AEMO has estimated to have support from existing and committed energy efficiency-related policies or market-led efficiency savings, and therefore does not capture as much investment in the longer term. The 2025 IASR provides a comparison of the savings trajectories applied.

The impact of reduced and increased energy efficiency on annual energy consumption in the NEM is shown in **Figure 46**. The corresponding impacts on the generation and storage developments required with varying levels of energy efficiency measures are relatively similar across CDPs and the counterfactual (see Appendix A2).

Figure 46 Impact of *Lower and Higher Energy Efficiency* on annual operational consumption in NEM – *Step Change*



Lower Energy Efficiency

Under the *Lower Energy Efficiency* sensitivity, forecast NEM-wide electricity consumption is 27 TWh higher than in *Step Change* by 2049-50, with an associated increase in peak demand. This requires additional generation and storage developments and results in an increase in total system cost for CDP 4 of approximately $9.5 billion[96,97] compared with CDP 4 in *Step Change*.

As seen in **Table 82**, the net market benefits of the preliminary ODP (against the 'no transmission' counterfactual DP) are higher by $5.68 billion under this sensitivity than in *Step Change*. This is a very similar outcome to the *Higher Demand* sensitivity and highlights that generally the value of transmission augmentations that improve access to new resources and increase the capacity for resource sharing increase with demand.

Table 82 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *Lower Energy Efficiency* sensitivity ($ million)

Class of market benefit	*Step Change*	*Lower Energy Efficiency sensitivity*	Difference
Generator, storage, and electrolyser capital deferral	23,319	27,362	4,043
Fixed operating and maintenance cost savings	3,817	5,622	1,806
Fuel cost savings	9,488	9,413	-75
Variable operating and maintenance cost savings	601	550	-51
Retirement cost	142	127	-16
Voluntary and involuntary load shedding reductions	163	171	8
Emissions reduction benefits	16	13	-2
REZ investment (REZ augmentations)	-97	-204	-108
Distribution expenditure (capital and operating costs)	130	165	35
System security costs	375	414	38
Gross market benefits	**37,953**	**43,632**	**5,679**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,407	0
Total net market benefits	**29,546**	**35,225**	**5,679**

As shown in **Table 83**, CDP 4 remains the top ranked CDP in this sensitivity in terms of net market benefits compared with other CDPs assessed.

[96] This contrasts the analysis presented in the table below, which demonstrates the change in the value of transmission from this sensitivity.

[97] More information is available in Appendix 9.

Table 83 Net market benefits and weighted net market benefits for key CDPs (in $ billion), core scenario outcomes and *Lower Energy Efficiency*

		Core scenario outcomes				*Lower Energy Efficiency* sensitivity			
CDP	**Description**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**	***Step Change***	***Step Change* rank**	**WNMB**	**WNMB rank**
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	5	27.86	1	35.23	5	30.47	1
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	4	27.85	2	35.25	2	30.46	2
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	7	27.85	3	35.22	7	30.46	3
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	8	27.84	4	35.20	9	30.45	4
CDP 25	CDP 4 without actionable North West Tasmania REZ option	29.50	10	27.82	7	35.20	8	30.45	5
CDP 27	CDP 4 with actionable Central Highlands REZ option	29.50	9	27.83	5	35.18	11	30.45	6
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	6	27.83	6	35.22	6	30.45	7
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	29.47	13	27.78	9	35.19	10	30.41	8
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	11	27.79	8	35.18	12	30.40	9
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	14	27.77	10	34.98	15	30.36	10
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	29.48	12	27.68	11	35.15	13	30.29	11
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	29.33	15	27.67	12	35.00	14	30.28	12
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	13	35.31	1	30.22	13
CDP 24	CDP 4 without actionable Project Marinus Stage 2	29.66	2	27.62	15	35.25	3	30.19	14
CDP 12	CDP 4 without actionable Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	29.08	16	27.63	14	34.64	17	30.19	15
CDP 26	CDP 4 without actionable North West Tasmania REZ option and actionable Project Marinus Stage 2	29.64	3	27.60	16	35.25	4	30.18	16
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	17	27.36	17	34.70	16	29.99	17
CDP 1	Least-cost DP for *Slower Growth*	28.07	18	26.84	18	33.39	18	29.29	18
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 kV option	24.58	19	24.40	19	30.17	19	26.97	19

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

Higher Energy Efficiency

Under the *Higher Energy Efficiency* sensitivity, forecast NEM-wide electricity consumption is 21 TWh lower than in *Step Change* by 2049-50, with an associated decrease in peak demand. This requires less generation and storage developments and results in a decrease in total system cost for CDP 4 of approximately $7.16 billion[98,99] compared with CDP 4 in *Step Change*.

As seen in **Table 84**, the net market benefits of the preliminary ODP (against the 'no transmission' counterfactual DP) are lower by $4.45 billion under this sensitivity than in *Step Change*, as higher forecast levels of energy efficiency savings reduce the need to use and share electricity supply, reducing the relative value of transmission augmentations that support efficient supply.

Table 84 Comparison of net market benefits delivered by CDP 4 in *Step Change* and in the *Higher Energy Efficiency* sensitivity ($ million)

Class of market benefit	*Step Change*	*Higher Energy Efficiency sensitivity*	Difference
Generator, storage, and electrolyser capital deferral	23,339	20,219	-3,100
Fixed operating and maintenance cost savings	3,821	2,602	-1,215
Fuel cost savings	9,488	9,406	-82
Variable operating and maintenance cost savings	601	636	35
Retirement cost	142	139	-3
Voluntary and involuntary load shedding reductions	163	119	-43
Emissions reduction benefits	16	13	-3
REZ investment (REZ augmentations)	-97	-57	40
Distribution expenditure (capital and operating costs)	130	121	-9
System security costs	375	306	-69
Gross market benefits	**37,978**	**33,506**	**-4,448**
Transmission Network (Actionable and Future ISP Projects)	-8,407	-8,407	0
Total net market benefits	**29,571**	**25,099**	**-4,448**

The increase in energy efficiency savings results in lower net market benefits for all CDPs assessed, with relatively small differences across the CDPs. This occurs as higher levels of energy efficiency reduce both electricity consumption and maximum demand which lowers electricity network utilisation and congestion, thereby reducing or deferring the need for transmission augmentations. As a result, some of the CDPs with lesser transmission upgrades provide very similar weighted net market benefits to CDP 4.

As shown in **Table 85**, CDP 4 remains highest ranked in this sensitivity in terms of net market benefits compared with other CDPs assessed. This highlights the robustness of the benefits delivered by transmission upgrades featured in CDP 4 despite the slightly lower net market benefits.

[98] This contrasts the analysis presented in the table below, which demonstrates the change in the value of transmission from this sensitivity.

[99] More information is available in Appendix A9.

Table 85 Net market benefits and weighted net market benefits for key CDPs (in $ billion), *Higher Energy Efficiency* and core scenario outcomes

		Core scenario outcomes				*Higher Energy Efficiency* sensitivity			
CDP	Description	*Step Change*	*Step Change* rank	WNMB	WNMB rank	*Step Change*	*Step Change* rank	WNMB	WNMB rank
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	29.55	5	27.86	1	25.10	7	25.81	1
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	29.58	4	27.85	2	25.14	4	25.81	2
CDP 25	CDP 4 without actionable North West Tasmania REZ Expansion	29.50	10	27.82	7	25.12	5	25.81	3
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	29.54	7	27.85	3	25.09	8	25.80	4
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	29.52	8	27.84	4	25.09	9	25.80	5
CDP 18	CDP 4 with actionable Eastern Victoria Reinforcement Option 1	29.54	6	27.83	6	25.10	6	25.79	6
CDP 27	CDP 4 with actionable Central Highlands REZ option	29.50	9	27.83	5	25.05	10	25.78	7
CDP 9	CDP 4 with actionable Queensland - New South Wales Interconnector (QNI) Connect	29.35	14	27.77	10	24.96	14	25.75	8
CDP 19	CDP 4 with actionable Eastern Victoria Reinforcement Option 2 (instead of Option 1)	29.47	13	27.78	9	25.04	12	25.74	9
CDP 3	Least-cost DP for *Accelerated Transition*	29.49	11	27.79	8	25.03	13	25.74	10
CDP 2	Least-cost DP for *Step Change*	29.77	1	27.67	13	25.45	1	25.69	11
CDP 10	CDP 4 without actionable Sydney Ring South power flow control option	29.33	15	27.67	12	24.93	15	25.65	12
CDP 17	CDP 4 without actionable Western Victoria Reinforcement program	29.48	12	27.68	11	25.05	11	25.64	13
CDP 26	CDP 4 without actionable North West Tasmania REZ Expansion and actionable Project Marinus Stage 2	29.64	3	27.60	16	25.35	2	25.63	14
CDP 24	CDP 4 without actionable Project Marinus Stage 2	29.66	2	27.62	15	25.31	3	25.62	15
CDP 12	CDP 4 without actionable Sydney Ring South – 500 kV option (Stage 1 and Stage 2)	29.08	16	27.63	14	24.70	16	25.62	16
CDP 28	CDP 4 with actionable Northern Transmission Project	28.99	17	27.36	17	24.52	17	25.30	17
CDP 1	Least-cost DP for *Slower Growth*	28.07	18	26.84	18	24.19	18	25.06	18
CDP 13	CDP 4 without actionable Sydney Ring North (Hunter Transmission Project), Sydney Ring South power flow control option, Sydney Ring South – 500 kV option	24.58	19	24.40	19	20.40	19	22.47	19

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

A6.9 Step 6: Finalising the optimal development path

As set out in Section A6.7, CDP 4 provides the highest weighted net market benefit while having comparable levels of potential regret relative to other low-regret CDPs. On this basis, CDP 4 represents the development path that best meets the ISP objective of delivering least-cost, secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies.

The sensitivity analyses in Section A6.8 provide a structured test of how alternative assumptions influence these outcomes. Across the range of sensitivities examined, CDP 4 continues to perform strongly in economic terms. It maintains the highest weighted net market benefits in the majority of sensitivities, as shown below in **Table 86**, demonstrating that its relative performance is stable to changes in key inputs.

This result provides evidence that the selection of CDP 4 is robust to uncertainty in:

- infrastructure delivery constraints,
- alternative demand trajectories, including data centre and large industrial load growth,
- the degree of CER coordination, and
- energy efficiency assumptions.

In two sensitivities, *Constrained Delivery* and *Higher Demand*, alternative CDPs rank higher on weighted net market benefits. These sensitivities reflect conditions where earlier or more accelerated transmission development is assessed to be beneficial. However, these same CDPs present risk to consumers of over-investment if conditions assumed under *Step Change* or *Slower Growth* are realised, and are therefore not considered superior to CDP 4. Further, CDPs that feature non-actionable delivery timings for some CDP 4 projects perform relatively worse under some sensitivities.

The sensitivity analysis therefore indicates that the inclusion and timely delivery of the transmission projects featured in CDP 4 continues to underpin efficient system outcomes, even where the optimal timing or scale of development opportunities may vary under different assumptions.

Combined, the results of the scenario and sensitivity analysis indicate that CDP 4:

- delivers the highest weighted net market benefits under the core scenario assumptions, and
- maintains strong relative performance across a range of uncertainties.

This provides a clear evidence base for identifying CDP 4 as the optimal development path in the 2026 ISP.

Table 87 presents the set of projects identified as actionable in the ODP in this 2026 ISP. Further details on these projects can be found in Appendix A5.

Table 86 Relativity of weighted net market benefits (in $ billion) for each key CDP across the sensitivity collection

CDP	Description	*Core Assumptions*	*Constrained Delivery*	*Higher Demand*	*No Further VPP Uptake*	*No Further CER Coordination*	*Lower Energy Efficiency*	*Higher Energy Efficiency*
Weighted net market benefits								
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	27.86	30.26	42.10	28.42	28.70	30.47	25.81
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	27.85	30.23	42.07	28.42	28.70	30.46	25.81
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	27.85	30.20	42.08	28.42	28.70	30.46	25.80
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	27.84	30.25	42.07	28.41	28.68	30.45	25.80
CDP 3	Least-cost DP for *Accelerated Transition*	27.79	30.34	42.16	28.35	28.64	30.40	25.74
CDP 2	Least-cost DP for *Step Change*	27.67	29.93	41.64	28.23	28.48	30.22	25.69
CDP 1	Least-cost DP for *Slower Growth*	26.84	28.78	38.91	27.43	27.74	29.29	25.06
Change in weighted net market benefits relative to most beneficial CDP								
CDP 4	CDP 2 with actionable Project Marinus Stage 2 and Central to North Queensland Reinforcement (Stage 1)	0.00	-0.08	-0.06	0.00	0.00	0.00	0.00
CDP 5	CDP 4 without actionable Central to North Queensland Reinforcement (Stage 1)	0.00	-0.11	-0.09	0.00	0.00	-0.01	0.00
CDP 7	CDP 4 without actionable Brisbane Area 275 kV Reinforcement	-0.01	-0.14	-0.08	-0.01	-0.01	-0.01	-0.01
CDP 15	CDP 4 without actionable Switching Station Near Wondalga	-0.02	-0.09	-0.09	-0.02	-0.02	-0.02	-0.01
CDP 3	Least-cost DP for *Accelerated Transition*	-0.07	0.00	0.00	-0.07	-0.07	-0.06	-0.08
CDP 2	Least-cost DP for *Step Change*	-0.19	-0.41	-0.52	-0.20	-0.23	-0.25	-0.12
CDP 1	Least-cost DP for *Slower Growth*	-1.01	-1.56	-3.25	-0.99	-0.96	-1.18	-0.75

Note: Cells shaded teal represent the top-ranked CDP of the CDPs presented in the table for each sensitivity.

Table 87 Network projects in the optimal development path in the 2026 ISP

Committed and anticipated transmission projects		In service timing[A]	Full capacity timing[B]
Project EnergyConnect Stage 2		October 2026	November 2027
HumeLink		December 2027	December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central-West Orana REZ Network Infrastructure Project		December 2028	December 2028
Western Renewables Link		November 2029	November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		2032	2032[C]
New England REZ Network Infrastructure Project[D]		January 2034	January 2034
Already actionable projects (confirmed in this ISP)	**Framework**	**In service timing[A]**	**Full capacity timing[B]**
Gladstone Project	QLD[E]	March 2029	Mid-2030[C]
Sydney Ring North (Hunter Transmission Project)	NSW[E]	November 2029	November 2029
Sydney Ring South	ISP	Power flow control: July 2030 500 kV assets: July 2033	Power flow control: July 2030 500 kV assets: July 2033
Victoria – New South Wales Interconnector West (VNI West)	NSW[E] ISP	South West REZ: August 2029 NSW-VIC: November 2030	South West REZ: August 2029[C] NSW-VIC November 2031
Project Marinus Stage 2	ISP	June 2034	December 2034
Newly actionable projects (identified in this ISP)	**Framework**	**Earliest feasible full capacity timing[B]**	
Western Victoria Reinforcement (future project in 2024 ISP)	VIC[E]	June 2029	
Tasmania REZ Expansion (future project in 2024 ISP)	ISP	July 2030	
Switching Station Near Wondalga	ISP	April 2031[C]	
Central to North Queensland Reinforcement (Stage 1) (smaller option of Queensland SuperGrid North project in 2024 ISP)	ISP	July 2031[C]	
Gippsland Offshore Wind Transmission Project (future project in 2024 ISP)	VIC[E]	Stage 1: July 2031; Stage 2 – Phase 1: July 2033; Stage 2 – Phase 2: July 2038	
Brisbane Area 275 kV Reinforcement	ISP	June 2032	
Central-West Orana REZ Expansion (future project in 2024 ISP)	NSW[E]	March 2033	
Future ISP projects[F]			
Interconnector projects	**Queensland – New South Wales Interconnector (QNI Connect)**		
Queensland	**Central to North Queensland Reinforcement (Stage 2), South West to South East Queensland Reinforcement**		
South Australia	**Northern Transmission Project[G]**		
Victoria	**Eastern Victoria Reinforcement, South West Victoria Expansion**		
Tasmania	**Second Tasmania REZ Expansion**		
Distribution projects			
New South Wales	**Hunter-Central Coast REZ Expansion, Dubbo Distribution Project**		

A. The in service date, advised by the project proponent, gives an indication of when construction and commissioning will be complete and equipment in-service.
B. The capacity release and timing, advised by the project proponent, is conditional on availability of suitable market conditions and good test results.
C. This date has been updated based on recent advice by the project proponent, and is different to the timing modelled in the final ISP.
D. This project is newly categorised as anticipated. It is progressing under the *Electricity Infrastructure Investment Act 2020* (NSW).
E. These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), *Electricity Infrastructure Investment Act 2020* (NSW), or the *National Electricity (Victoria) Act 2005* (Vic), rather than the ISP framework.
F. This list shows future ISP projects which are identified as part of the ODP in *Step Change* or are subject to an ongoing regulatory investment test for transmission (RIT-T). Appendix A5 Network Investments provides information about additional future ISP projects identified in only one scenario.
G. AEMO considers ElectraNet should continue the Northern Transmission Project RIT-T. This will allow further assessment of local factors, system resilience, option value, future load development, and additional credible options.

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's *Cost Benefit Analysis Guidelines*, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand apply, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	-	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity, and is a form of 'demand flexibility'.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.

Term	Acronym	Explanation
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Economic offloading	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. This may also be referred to as economic ‘spill’ or ‘spilled energy’.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Mid-scale	-	Generation and storage typically connected to the distribution network rather than to either the transmission network or behind the meter at a business or residence. For the 2026 ISP, these resources are assumed to have a generation or charge/discharge capacity of between 5 MW and 30 MW. For ease of reporting in this document, mid-scale generation and storage are sometimes included within the totals for utility-scale generation and storage. In other AEMO documents, such as the *Demand Side Factors Information Guidelines* and the *ISP Methodology*, these resources are sometimes referred to as ‘other distributed resources’.
National Electricity Rules	NER	The Rules are legally binding rules made under the National Electricity Law, which govern the operation of the National Electricity Market and the ways in which AEMO manages power system security. The Rules also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The Rules are mainly made by the AEMC having regard to the National Electricity Objective.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER’s Cost Benefit Analysis Guidelines. The net market benefits of the ODP through to 2050 is the difference between the cost of the ODP and the cost of a ‘counterfactual’ development path which has no new transmission build.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate energy to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: “solar, wind, biomass, hydro, and hydrogen turbines”. Variable renewable energy is a subset of this group, explained below.

Term	Acronym	Explanation
Renewable energy zone	REZ	An area identified in the ISP as a high-quality resource area where a cluster of large renewable energy projects can be developed using economies of scale.
Renewable lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Rooftop solar and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For this ISP, AEMO has considered three scenarios: *Slower Growth*, *Step Change* and *Accelerated Transition*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how sensitive modelling outcomes are to a change in input or assumption (or a collection of related inputs and assumptions).
Spill	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. Also referred to as 'economic offloading' or 'spilled energy'.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Utility-scale or utility	-	For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.