

# Appendix A6. Cost-Benefit Analysis

December 2025

Appendix to the Draft 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 first [Reconciliation Action Plan](#) in May 2024. '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 Draft 2026 Integrated System Plan (ISP) which is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>. AEMO publishes the Draft 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 document is generally based on information available to AEMO as at 1 July 2025 unless otherwise indicated.

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### Version control

Version	Release date	Changes
1	10/12/2025	First release

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## Executive summary

AEMO's *Integrated System Plan (ISP)* is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path (ODP) sets out the needed generation, storage, and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

This appendix provides a detailed walkthrough of the process used in this Draft 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 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 principles and methodologies in the *ISP Methodology*<sup>1</sup>, updated in June 2025 to complete a four-yearly review requirement and to incorporate the Energy Minister's response<sup>2</sup> to the review of the ISP.

This appendix complements the generation and storage developments provided in detail in Appendix A2.

### The proposed optimal development path

The ODP covers a range of generation, storage, transmission, and distribution developments. 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 energy system in line with government policy, while minimising cost to consumers.

Since the 2024 ISP, three major transmission projects have become anticipated – HumeLink, Hunter-Central Coast REZ Network Infrastructure project, and Project Marinus Stage 1. The costs and benefits of these projects are not assessed in this Draft 2026 ISP.

The ODP in this Draft 2026 ISP has identified seven projects that retain their actionable status since the previous ISP as these projects continue to deliver net market benefits at actionable timings and would result in a decrease in costs for consumers. Three projects – Western Victoria Reinforcement program, Gippsland Offshore Wind Transmission and Switching Station Near Wondalga – have been identified as new actionable projects, while two projects (QNI Connect and Northern Transmission Project) are subject to further analysis following publication of the Draft 2026 ISP to ascertain whether they would provide optimal benefit to consumers as previously identified in the 2024 ISP.

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

<sup>2</sup> At [ecmc-response-to-isp-review.pdf](#).

**Table 1 Network projects in the proposed optimal development path in the Draft 2026 ISP**

Committed and anticipated transmission projects		In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>B</sup>
Project EnergyConnect – Stage 2		October 2026	30 November 2027
HumeLink		1 December 2027	1 December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central West Orana REZ Network Infrastructure Project		1 December 2028	1 December 2028
Western Renewables Link (uprated)		30 November 2029	30 November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		June 2031	June 2031
Projects likely to remain actionable	Actionable framework	In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>A</sup>
Gladstone Project	QLD <sup>C</sup>	1 March 2029	1 March 2029
Sydney Ring North (Hunter Transmission Project)	NSW <sup>D</sup>	November 2029	November 2029
Sydney Ring South power flow controller option	ISP	1 July 2030	1 July 2030
Waddamana to Palmerston transfer capability upgrade	ISP	June 2030	December 2030
Victoria – New South Wales Interconnector West (VNI West)	ISP	30 November 2030	30 November 2031
New England REZ Network Infrastructure Project	NSW <sup>D</sup>	July 2032	July 2032
Project Marinus Stage 2	ISP	June 2034	December 2034
Projects actionable in 2024 ISP, requiring ongoing analysis	Actionable framework	In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>B</sup>
Northern Transmission Project <sup>E</sup>	ISP	July 2029	July 2029
Queensland – New South Wales Interconnector (QNI) Connect <sup>F</sup>	ISP	March 2032	2034
Projects likely to be identified as newly actionable	Actionable framework	Earliest feasible in service timing <sup>A</sup>	Earliest feasible full capacity timing <sup>B</sup>
Switching Station Near Wondalga (new)	ISP	2029	2029
Western Victoria Reinforcement program (future project in 2024 ISP)	VIC <sup>G</sup>	1 June 2029	1 June 2029
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC <sup>G</sup>	Stage 1: 2032 Stage 2 (Phase 1): 2035 Stage 2 (Phase 2): 2039	Stage 1: 2032 Stage 2 (Phase 1): 2035 Stage 2 (Phase 2): 2039
Future ISP projects			
<b>New South Wales</b>	Central West Orana REZ Expansion, Sydney Ring South – 500 kV option		
<b>Queensland</b>	Central Queensland to Southern Queensland Expansion <sup>H</sup> , Facilitating Power to South East Queensland, Facilitating Power to Central Queensland		
<b>Victoria</b>	Eastern Victoria Reinforcement program, South West Victoria Expansion program		

A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.  
 B. The capacity release and timing are conditional on availability of suitable market conditions and good test results.  
 C. This project will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the NER framework for actionable ISP projects.  
 D. These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the NER framework for actionable ISP projects.  
 E. Previously known as the Mid North South Australia REZ project. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including confirmation of generation and storage project locations as a result of government policies and programs. Based on current cost benefit analysis, this project is not included in proposed ODP, ODP project counts, cost benefit assessment totals and other metrics in this Draft 2026 ISP.  
 F. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including alignment with the Queensland Energy Roadmap.  
 G. This project will progress under the *National Electricity (Victoria) Act 2005* (Vic) rather than the NER framework for actionable ISP projects.  
 H. Previously known as Queensland SuperGrid South. This project has changed from being an ‘actionable’ project in the 2024 ISP to being a ‘future’ ISP project in the Draft 2026 ISP.

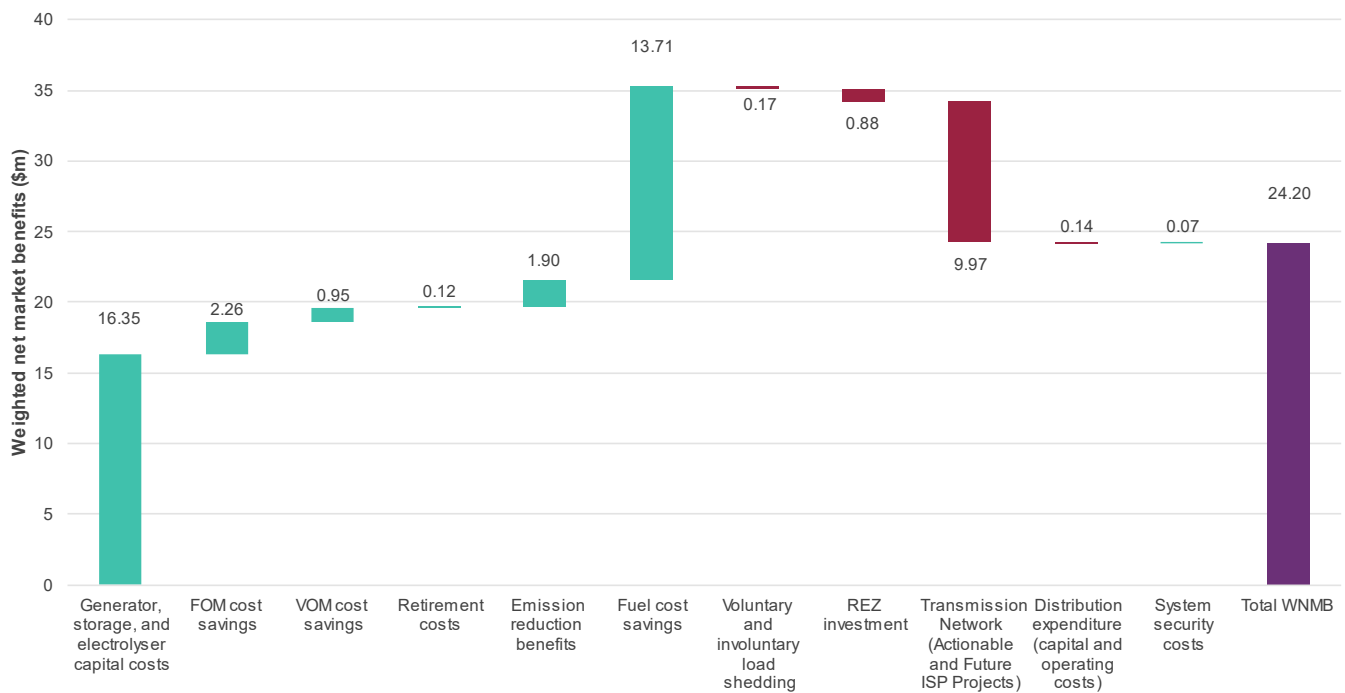
## Net market benefits of the ODP

This proposed ODP is projected to reduce costs that the system would otherwise need to bear by the order of \$24 billion, on **weighted basis across the scenarios**, which includes emissions reduction benefits valued at \$2 billion. As further discussed in Section A6.3, weighted net market benefits have remained similar with the identified benefits in the 2024 ISP.

To 2050, the annualised capital cost in present value (PV) terms of the future capital costs of all utility-scale generation, storage, firming and transmission and distribution network in the ODP would be \$128 billion in the *Step Change* scenario. As the assets have a technical life beyond 2050, the total present value of these investments is \$156 billion. The transmission element of this capital cost would be \$9 billion in PV terms, or 7% of the total. All other 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 balanced consideration of the risks of over- and under-investment across the scenario collection, and it provides the highest **weighted net market benefits** across the three scenarios (see **Figure 1**).

**Figure 1 Weighted net market benefits of the proposed ODP by category**



**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	WNMB Rank	Worst weighted regrets	WWR Rank
4	ODP (Least-cost DP in <i>Step Change</i> scenario with actionable Switching Station Near Wondalga)	12.64	25.48	33.57	24.20	1	0.42	5
6	ODP with Sydney Ring South – 500 kV option	12.42	25.35	33.94	24.18	2	0.48	12
16	ODP without New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI)	14.18	24.95	32.84	24.17	3	0.40	2
10	ODP with Eastern Victoria Reinforcement program (Option 2) instead of the smaller option (Option 1)	12.57	25.46	33.55	24.16	4	0.44	8
2	Least-cost DP in <i>Step Change</i> scenario	12.64	25.48	33.43	24.16	5	0.42	3
20	ODP without Waddamana to Palmerston transfer capacity upgrade	12.64	25.42	33.37	24.12	6	0.42	4
9	ODP with Eastern Victoria Reinforcement program (Option 1)	12.45	25.42	33.55	24.11	7	0.47	10
8	ODP with Central Queensland to Southern Queensland Expansion	12.48	25.25	33.76	24.10	8	0.46	9
7	ODP with Dubbo Distribution Project	12.42	25.45	33.45	24.09	9	0.48	13
15	ODP without Western Victoria Reinforcement program	12.63	25.36	33.30	24.07	10	0.42	6

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

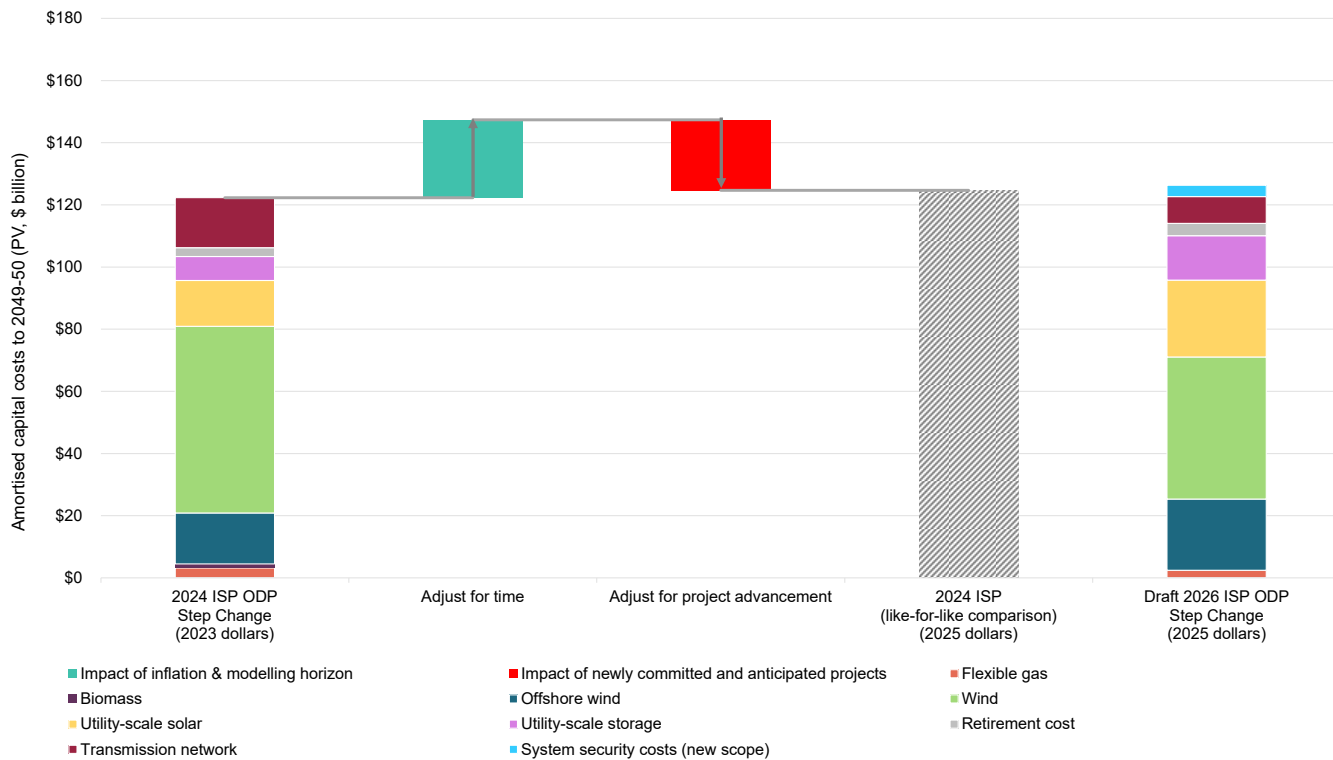
To incorporate the Energy Minister’s response<sup>3</sup> to the review of the ISP, the total system cost assessed in the Draft 2026 ISP now includes the costs of distribution network augmentations, system security, and other distributed resources<sup>4</sup>.

**Figure 2** presents this inclusion, and how the total system capital costs in the Draft 2026 ISP are compared with the total system capital cost figure in the 2024 ISP. The figure shows that, excluding these new scopes, the estimate for the total system capital costs for the Draft 2026 ISP is of similar magnitude as that in the 2024 ISP.

<sup>3</sup> At <https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf>.

<sup>4</sup> 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 MW.

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



### Sensitivity analysis confirms the selection of the ODP

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

The Draft 2026 ISP presents a range of sensitivities, including:

- *Constrained Delivery* which explores the impact of limitations in supply chain, workforce availability, or other factors affecting the cost and timing of delivery of energy infrastructure,
- alternative coal retirement scenarios which assess how the pace for coal-fired generation capacity retirements affect the development opportunities in the NEM,
- alternative gas development projections (GDPs) that explore the impact of different gas supply volumes available to support flexible gas generation operations in the NEM power system, and
- alternative assumptions on demand-side factors such as *No Further CER Coordination* and *Lower Energy Efficiency*.

As **Table 3** shows, the CDP4 delivers the highest-ranked weighted net market benefits across six of the 10 sensitivities; in all but one sensitivity, CDP4 remains either the best or second-best CDP in weighted net market benefits, and only the *Constrained Delivery* sensitivity, which favours an even more accelerated delivery of transmission augmentations, sees CDP4 rank lower than second-best.

CDP4 represents the CDP with the highest weighted net market benefits across the CDP collection; and given its robust performance across the set of alternative assumptions tested through sensitivity analysis, AEMO identifies CDP4 as the proposed ODP.

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

CDP	Description	Core assumptions	Constrained Delivery	Faster Coal Retirements	Slower Coal Retirements	GDP Option 1	GDP Option 2	Underinvestment GDP	No Further CER Coordination	Lower Energy Efficiency
<b>Weighted net market benefits</b>										
4	CDP2 with actionable Switching Station Near Wondalga	24.20	20.39	26.96	25.47	23.89	24.12	24.55	24.95	25.41
6	CDP4 with actionable Sydney Ring South – 500kV option (Stages 1 and 2)	24.18	20.71	26.94	25.43	23.86	24.10	24.53	24.92	25.40
16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	24.17	20.35	26.96	25.57	23.85	24.08	24.50	24.88	25.53
10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	24.16	20.43	26.92	25.44				24.92	25.38
2	Least-cost DP for <i>Step Change</i>	24.16	20.44	26.93	25.45	23.85	24.09	24.52	24.92	25.38
20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	24.12	20.34	26.89	25.42				24.87	25.34
3	Least-cost DP for <i>Accelerated Transition</i>	23.96	20.74							
<b>Change in weighted net market benefits relative to most beneficial CDP</b>										
4	CDP2 with actionable Switching Station Near Wondalga	0.00	-0.35	0.00	-0.10	0.00	0.00	0.00	0.00	-0.12
6	CDP4 with actionable Sydney Ring South – 500kV option (Stages 1 and 2)	-0.02	-0.03	-0.02	-0.14	-0.02	-0.02	-0.02	-0.03	-0.13
16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	-0.02	-0.39	0.00	0.00	-0.04	-0.04	-0.05	-0.07	0.00
10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	-0.03	-0.31	-0.04	-0.13				-0.03	-0.16
2	Least-cost DP for <i>Step Change</i>	-0.03	-0.30	-0.03	-0.12	-0.03	-0.03	-0.03	-0.03	-0.15
20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	-0.08	-0.40	-0.07	-0.16				-0.08	-0.20
3	Least-cost DP for <i>Accelerated Transition</i>	-0.24	0.00							

Note: Cells shaded teal represent the top-ranked CDP amongst those presented in the table for each sensitivity. Cells shaded grey indicate that the CDP was not tested for the given sensitivity.

## Key changes since the 2024 ISP

AEMO has incorporated several changes since publication of the 2024 ISP in response to stakeholder feedback, legislative changes, and recent market developments, including:

- the inclusion of newly committed, anticipated, and policy-supported projects as per the July 2025 Generation Information<sup>5</sup> update,
- updates to policy inputs to reflect the latest updates from state and federal governments, and revisions to the assumptions informing emissions budgets to reflect the most recent emissions accounting,
- updated capital costs and fuel prices,
- implementation of technology-specific weighted average cost of capital (WACC),
- revision of virtual power plant (VPP) and vehicle-to-grid (V2G) forecasts,
- revision of demand forecasts and rooftop and other small-scale solar capacity forecast,
- reduction of hydrogen demand forecast and change in the approach to locating electrolysers from sub-region to within renewable energy zones (REZs),
- inclusion of some high-level distribution network modelling,
- changes to transmission project assumptions and transmission network representation,
- implementation of gas development projections, and
- updated methodology to produce VRE traces.

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<sup>5</sup> At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

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

This appendix details the cost-benefit analysis (CBA) implemented 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 illustrates the process of determining the least-cost DP and presents the projects that make up each scenario's least-cost DP.
- A6.4 outlines the development of the set of CDPs based on the least-cost DPs.
- A6.5 provides a detailed assessment of individual transmission projects by examining their individual impact and the value that they provide by being declared as actionable projects.
- A6.6 identifies the proposed ODP based on the core set of assumptions.
- A6.7 tests the resilience and robustness of the ODP and a subset of the CDP collection to changes in assumptions through sensitivity analysis.
- A6.8 finalises the identification of the proposed 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 *Transmission Expansion Options Report*. These costs may appear differently to those presented in Appendix A5, which displays the cost for delivery in a fixed year.

This appendix is supported by the **Generation and Storage Outlook Workbook**<sup>6</sup>, which also provide a breakdown of the difference in total system costs between CDPs.

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<sup>6</sup> At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp>.

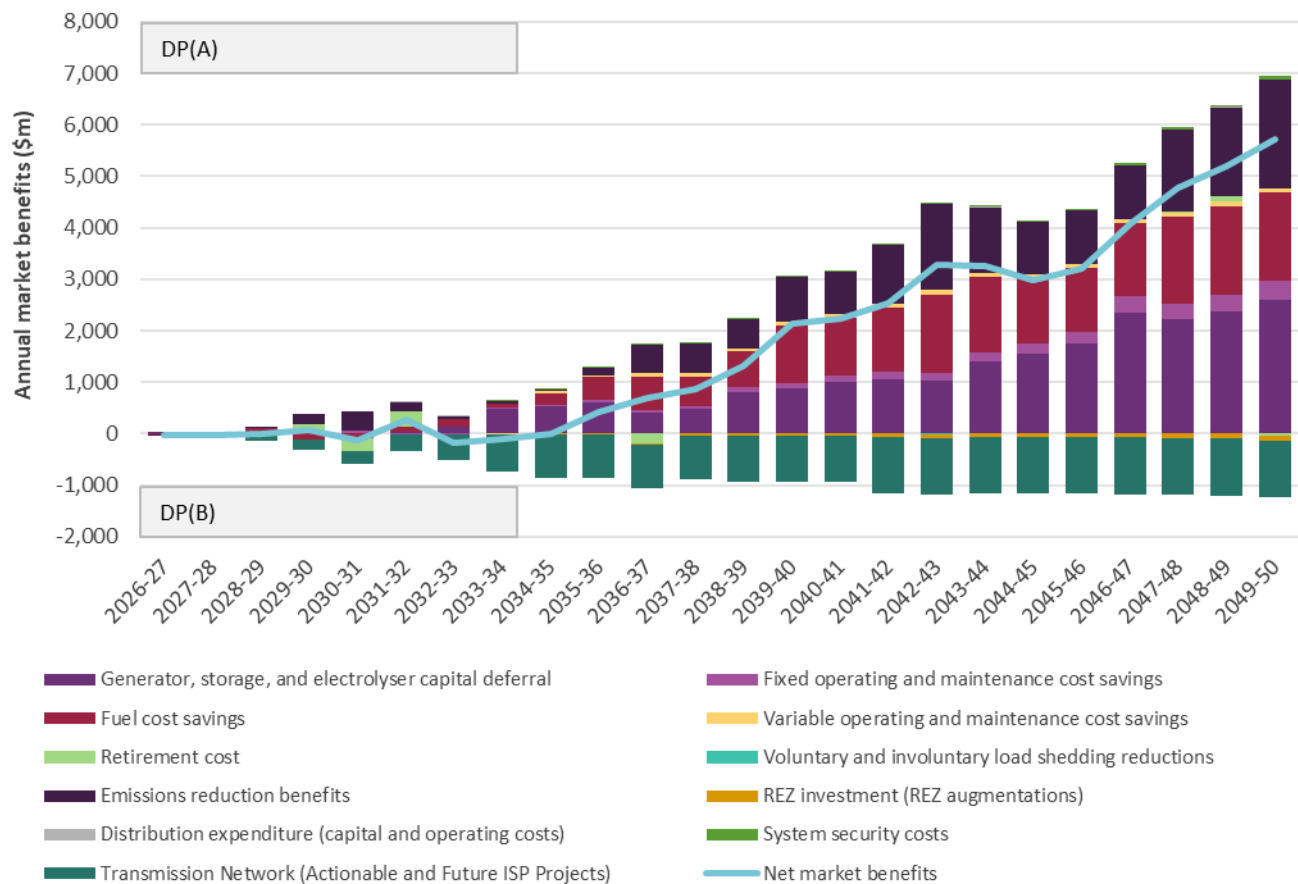


### Interpreting the graphics in this appendix

This appendix presents a number of charts comparing the projected benefits of two different development paths 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**

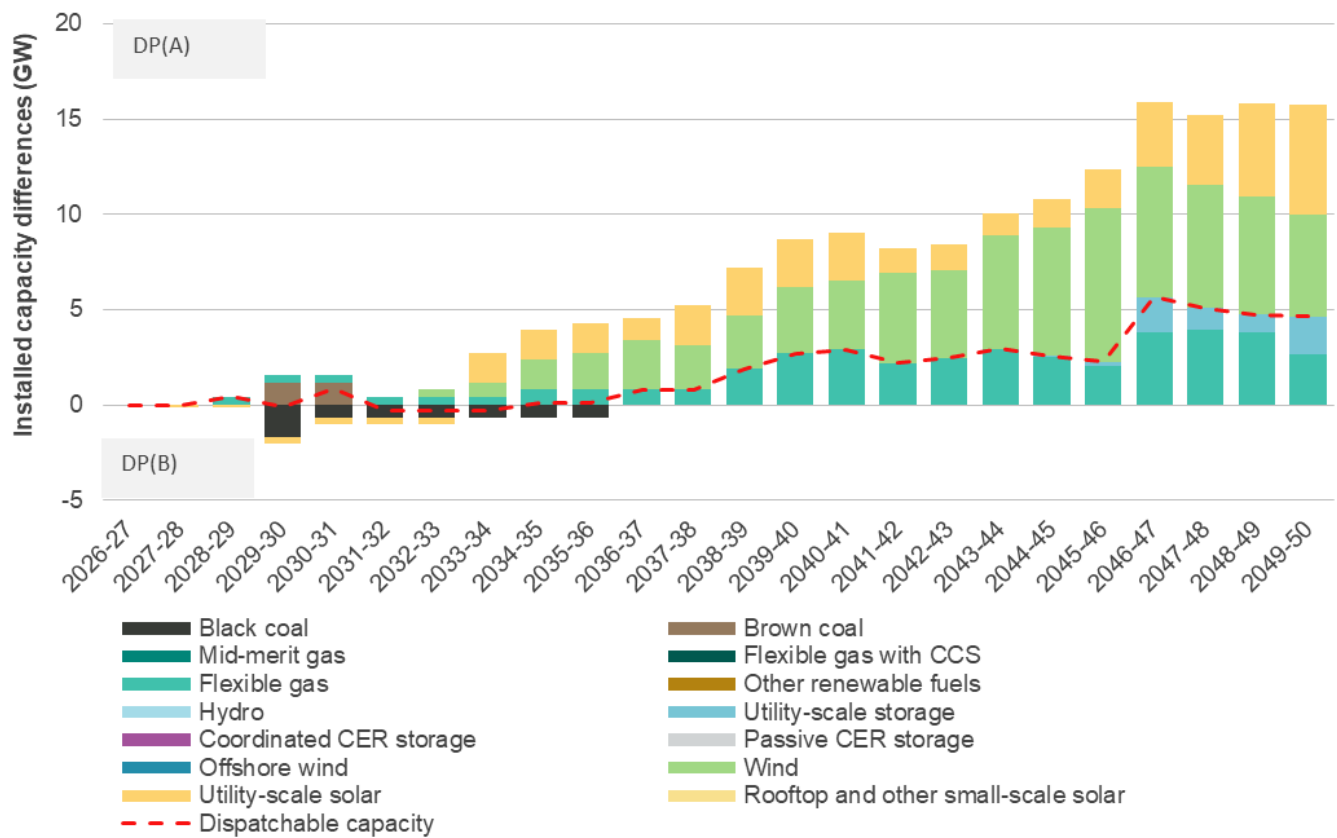


This appendix also presents charts comparing the projected capacity and generation differences over the outlook period of two different development paths, as shown in the example figure below. When interpreting charts like the one below in **Figure 4**:

- 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.

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**



## Key changes since the 2024 ISP

### Methodology changes relevant to the cost-benefit analysis

Following an extensive stakeholder consultation process, AEMO made the following key improvement to its ISP Methodology that focus on enhancing the accuracy of the energy system modelling that informs the CBA:

- adjusting the sub-regional topology and sub-regional electricity demand allocations,
- including distribution network considerations to facilitate CER operation and uptake of other distributed resources,
- expanding the gas supply model to determine gas development projections, including investment options such as gas network, storage, and supply augmentation opportunities from the 2025 *Gas Infrastructure Options Report*,
- assessing previously actionable projects at only the project proponent's timing within the actionable window,
- modelling future hydrogen electrolyzers within REZs rather than at ports, and
- adjusting representation of transmission network capabilities for REZs to better represent the impact of large dispatchable loads on transmission limits.

### Key inputs and assumptions

As well as changes to the methodology, there have been significant revisions to inputs and assumptions, detailed in the 2025 *Inputs, Assumptions and Scenarios Report (IASR)*<sup>7</sup>. Key changes can be summarised as:

- updated renewable energy targets and policies to reflect developments in federal and state government policies,
- revised carbon emissions budgets across scenarios to reflect a spread of emissions reduction for the electricity sector that will support the decarbonisation of Australia's economy, aligned with government policy, including Australia's recently developed 2035 emissions target for the Federal Government's Net-Zero Plan<sup>8</sup>,
- an additional 4 GW wind, 4 GW utility-scale solar and 1 GW flexible gas that are now committed or anticipated, as confirmed in AEMO's July 2025 Generation Information update,
- technology-specific weighted-average cost of capital (WACCs) to account for the different financial risks and assumptions appropriate for each technology and scenario,
- revised costs, capacity limits and renewable resource estimates outlined in AEMO's 2025 *Electricity Network Options Report*<sup>9</sup> and CSIRO's 2024-25 *GenCost*<sup>10</sup> publication, and reflecting revised wind farm hub heights of 150 metres, and
- updated energy demand forecasts including CER, data centres, and reduced demand for hydrogen consumption across all scenarios.

<sup>7</sup> At [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc\\_lang=en](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en).

<sup>8</sup> At [dceew.gov.au/sites/default/files/documents/net-zero-report.pdf](https://dceew.gov.au/sites/default/files/documents/net-zero-report.pdf).

<sup>9</sup> [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?la=en](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?la=en).

<sup>10</sup> Available to download at [https://www.csiro.au/-/media/Energy/GenCost/GenCost-2024-25-Final\\_20250728.pdf](https://www.csiro.au/-/media/Energy/GenCost/GenCost-2024-25-Final_20250728.pdf).

## A6.2 Approach to the cost-benefit analysis

The Draft 2026 ISP applied AEMO's *ISP Methodology*<sup>11</sup> 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*<sup>12</sup> and *Cost Benefit Analysis Guidelines*<sup>13</sup> 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<sup>14</sup>,
- 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)<sup>15</sup> (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 outside of, its actionable window to assess whether a project that was previously actionable should continue to be progressed.

<sup>11</sup> 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](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).

<sup>12</sup> At <https://www.aer.gov.au/industry/registers/resources/guidelines/forecasting-best-practice-guidelines>.

<sup>13</sup> At <https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20guidelines%20-%202024%20-%20Version%203.pdf>.

<sup>14</sup> 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).

<sup>15</sup> 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.

- 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 in the classes of market benefits as listed in 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 **weighted net market benefits (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 that were derived considering the insights of an expert stakeholder panel and AEMO’s assessment of scenario likelihood (see Appendix A1).
- **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 **worst weighted regrets (WWR)** reflect the highest amount of weighted ‘regrets’ across the scenarios. The worst weighted regrets are 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 and 2026 ISP Scenario weighting<sup>16</sup> 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
<i>Slower Growth</i>	27%
<i>Step Change</i>	46%
<i>Accelerated Transition</i>	27%

<sup>16</sup> 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<sup>17</sup> 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 CDP 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 (captured above – 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)<sup>18</sup> are captured as a positive market benefit,
- **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 CDP 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 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
- **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).

<sup>17</sup>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.

<sup>18</sup> At <https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024>.



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.

## A6.3 Step 1: Determining least-cost development paths for each scenario

The first stage in the CBA process was to determine the least-cost DP which contains the mix of generation, storage, and network developments that would maximise the market benefits described in A6.2.3 for each individual scenario. This was based on testing thousands of permutations of network development options and timings, and on the impact that network developments have on generation and storage outcomes. As the classes of market benefit considered all 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 used to search for the least-cost DP in each scenario was as follows:

- The Single-Stage Long-Term<sup>19</sup> (SSLT) model was used as a screening tool to identify the transmission network augmentations likely to minimise system costs, indicating their timing and scale of augmentation.
- The Detailed Long Term (DLT) capacity outlook model was then used to explore many DPs that are constructed based on the indicative transmission network developments provided by the SSLT modelling. This more detailed assessment (which ensures network projects are modelled to their defined network option technical capabilities and project timings) tested which combination of network developments would produce the lowest total system costs.
- For network projects that were previously actionable, this process examined the impacts of delivering a project at its proponent timing versus delayed investment outside of the project's actionable window (including never investing in the project). For other projects not currently actionable, the process identified a 'cross-over point' such that the timing of the option's development starts to deliver positive net market benefits. Alternative delivery timings were then tested around this 'cross-over point' to determine the optimal delivery timing of that option.

This process was conducted to understand the combination of projects or project timings that deliver the lowest system cost in each scenario.

This section presents a concise summary of this process by detailing the least-cost DP for each scenario and comparing it to a subset of alternative DPs to illustrate the reasons for identifying a DP as optimal in a given scenario. This includes consideration of alternative projects or project options to demonstrate that these have been considered and why they were not optimal.

While many alternative DPs<sup>20</sup> were developed and analysed to explore a wide range of development possibilities across options and timings for each scenario, only a subset of the alternative DPs are presented in the tables below. These were selected to demonstrate the merits of bigger, additional, or delayed augmentation options for a relevant transmission element in searching for the least-cost DP.

This process of searching for the least-cost DP is illustrated in **Figure 5** and further explained in the *ISP Methodology*<sup>21</sup>, including a worked example of the methodology described above.

<sup>19</sup> Further information on the differences between the Single-Stage Long-Term model and the Detailed Long-Term Model is in the *ISP Methodology*.

<sup>20</sup> DPs, as defined in the Glossary, are not scenario-specific, and can be explored in more than one scenario. DPs are not necessarily optimal in any scenario – generally, many DPs are tested to determine which DP is optimal in any given scenario.

<sup>21</sup> 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



This section highlights some of the alternative options assessed, focusing on some credible alternatives or further augmentations.

### A6.3.1 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 the *Step Change* scenario 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 sub-region and Greater Melbourne and Geelong sub-region. Additionally, some of the projects, like Victoria – New South Wales Interconnector West (VNI West) and QNI Connect, provide additional capacity to share resources between regions and access to major utility-scale storage developments like Snowy 2.0 and Borumba Pumped Hydro.

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

Table 5 presents the timings of relevant network development options in the least-cost DP for *Step Change* and a subset of relevant alternative DPs that were tested during the process of determining the least-cost DP.

**Table 5** Subset of development paths assessed in Step Change

Network option	EISD	Least-cost DP	Alternative DP1	Alternative DP2	Alternative DP3
Gladstone Project	2028-29	2028-29	2028-29	2028-29	2028-29
Auburn River Switching Station <sup>A</sup>	2031-32	2033-34	2033-34	2033-34	2033-34
Queensland SuperGrid South <sup>A</sup>	2031-32	2035-36	2035-36	2035-36	2035-36
Queensland – New South Wales Interconnector (QNI) Connect	2033-34 <sup>B</sup>	2033-34	2033-34	2033-34	2033-34
New England REZ Network Infrastructure Project (REZ option)	2032-33	2032-33	2032-33	2032-33	2032-33
New England REZ Network Infrastructure Project (Flow path option)	2032-33	2032-33	2032-33	2032-33	2032-33
Sydney Ring North (Hunter Transmission Project 1.0)	2029-30	2029-30	2029-30	2029-30	2029-30
Sydney Ring South Option 2	2030-31		2030-31		
Sydney Ring South power flow controller option	2030-31	2030-31			2030-31
Sydney Ring South - 500 kV option (Stage 1)	2033-34	2037-38		2033-34	2037-38
Sydney Ring South - 500 kV option (Stage 2)	2033-34	2037-38		2033-34	2037-38
Dubbo Distribution Project	2030-31	2032-33	2032-33	2032-33	2032-33
Switching Station Near Wondalga	2029-30	2031-32	2031-32	2031-32	2031-32
Victoria – New South Wales Interconnector West (VNI West)	2031-32	2031-32	2031-32	2031-32	2031-32
Western Victoria Reinforcement program	2028-29	2028-29	2028-29	2028-29	2028-29
South West Victoria expansion program	2033-34	2035-36	2035-36	2035-36	2035-36
Gippsland Offshore Wind Transmission Stage 1	2031-32	2031-32	2031-32	2031-32	2031-32
Gippsland Offshore Wind Transmission Stage 2 (Phase 1)	2033-34	2034-35	2034-35	2034-35	2034-35
Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	2038-39	2038-39	2038-39	2038-39	2038-39
Eastern Victoria Reinforcement program Option 1	2031-32				
Eastern Victoria Reinforcement program Option 2	2031-32	2033-34	2033-34	2033-34	2033-34
Heywood Interconnector Upgrade	2031-32				
Northern Transmission Project	2029-30				
SESA-CSA Transmission Upgrade	2029-30				
Project Marinus Stage 2	2034-35	2034-35	2034-35	2034-35	2034-35
Burnie-Hampshire Hills transfer capacity upgrade (North West Tasmania REZ)	2030-31				2030-31
Waddamana to Palmerston transfer capacity upgrade (Central Highlands REZ)	2030-31	2030-31	2030-31	2030-31	
<b>Reduction in net market benefits (\$ million) compared with the least-cost DP</b>		-	<b>2,868</b>	<b>80</b>	<b>89</b>

A. Part of the Central Queensland to Southern Queensland Expansion project.

B. For QNI, proponent timing is different than EISD. AEMO has tested the optimal timing considering the proponent's timing.

Note: Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period under this scenario.

The alternative DPs selected and contrasted above demonstrate:

- the reason for preferring the smaller Sydney Ring South power flow controller option and expanding later over the larger Sydney Ring South Option 2 (Alternative DP1),
- the reason for preferring the smaller Sydney Ring South power flow controller option and not the larger staged version of Sydney Ring South Option 3 (Alternative DP2), and
- how the Central Highlands REZ in Tasmania is the preferred development option to the North West Tasmania REZ to support Tasmania in meeting the Tasmania Renewable Energy Target (Alternative DP3).

### Benefits of developing Sydney Ring South power flow controller option and later the 500 kV option instead of Sydney Ring South Option 2

The least-cost DP for *Step Change* features multiple options to provide adequate supply to the Sydney, Newcastle and Wollongong sub-region as demand increases throughout the outlook period. Augmentations to support transfer capacity both north and south of Sydney are included. Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South power flow controller option are both developed at their EISDs of 2029-30 and 2030-31. The initial Sydney Ring South power flow controller option upgrade delivers improved power flow sharing between the northern and southern segments of the CNSW-SNW flow paths, which allows a greater net transfer of power into Sydney, Newcastle, Wollongong (SNW) sub-region.

A further expansion of Sydney Ring South (providing a two-stage 500 kV upgrade) is developed in 2037-38 to provide an additional increase of 3,600 MW transfer capacity, needed to meet growing energy consumption forecast in the Sydney, Newcastle and Wollongong region from large industrial loads, electric vehicles, electrification, and general population growth.

Alternative DP1 considers an alternative approach to upgrading Sydney Ring South by developing Option 2 instead of the Sydney Ring South – power flow controller option and 500 kV option, providing greater power flow capacity upgrades than the power flow controller option to transfer energy from Central New South Wales, although this comes at a higher cost, and inhibits the 500 kV option upgrades from taking place.

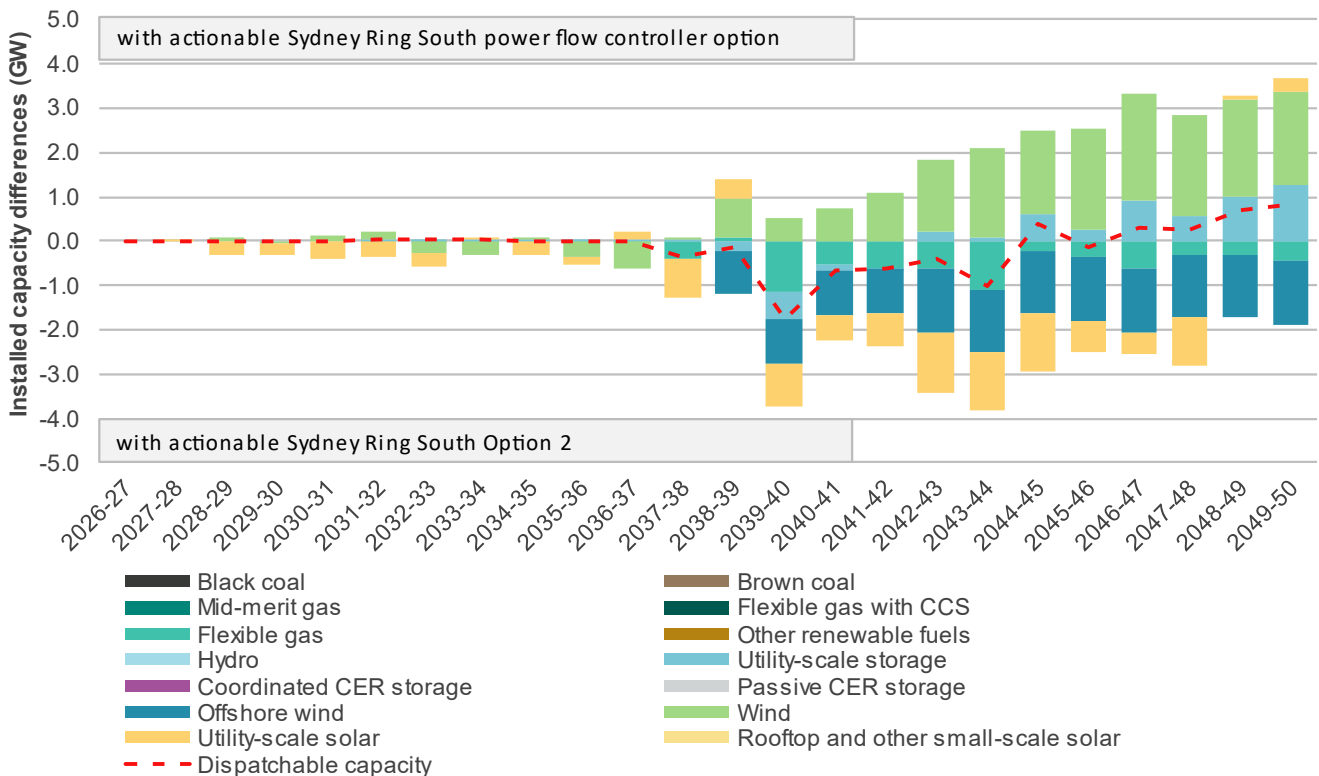
The relative market benefits between these two DPs are presented in **Table 6**, which demonstrates that developing expanded Sydney Ring South transfer capacity (Sydney Ring South - power flow controller option and Sydney Ring South – 500 kV option Stages 1 and 2) as a future project results in an overall increase in relative market benefits of \$2,868 million as opposed to improving power flows by delivering Sydney Ring Option 2.

The main driver of these benefits is avoiding the need for additional flexible gas capacity and offshore wind in SNW sub-region and additional utility-scale solar in Central New South Wales (see **Figure 6**). The augmentation provides firm capacity to provide reliability to the major load centre. The improved power flows from Central New South Wales that Option 2 provides are not sufficient to meet the energy consumption forecast in this sub-region, resulting in the preference for the power flow control option.

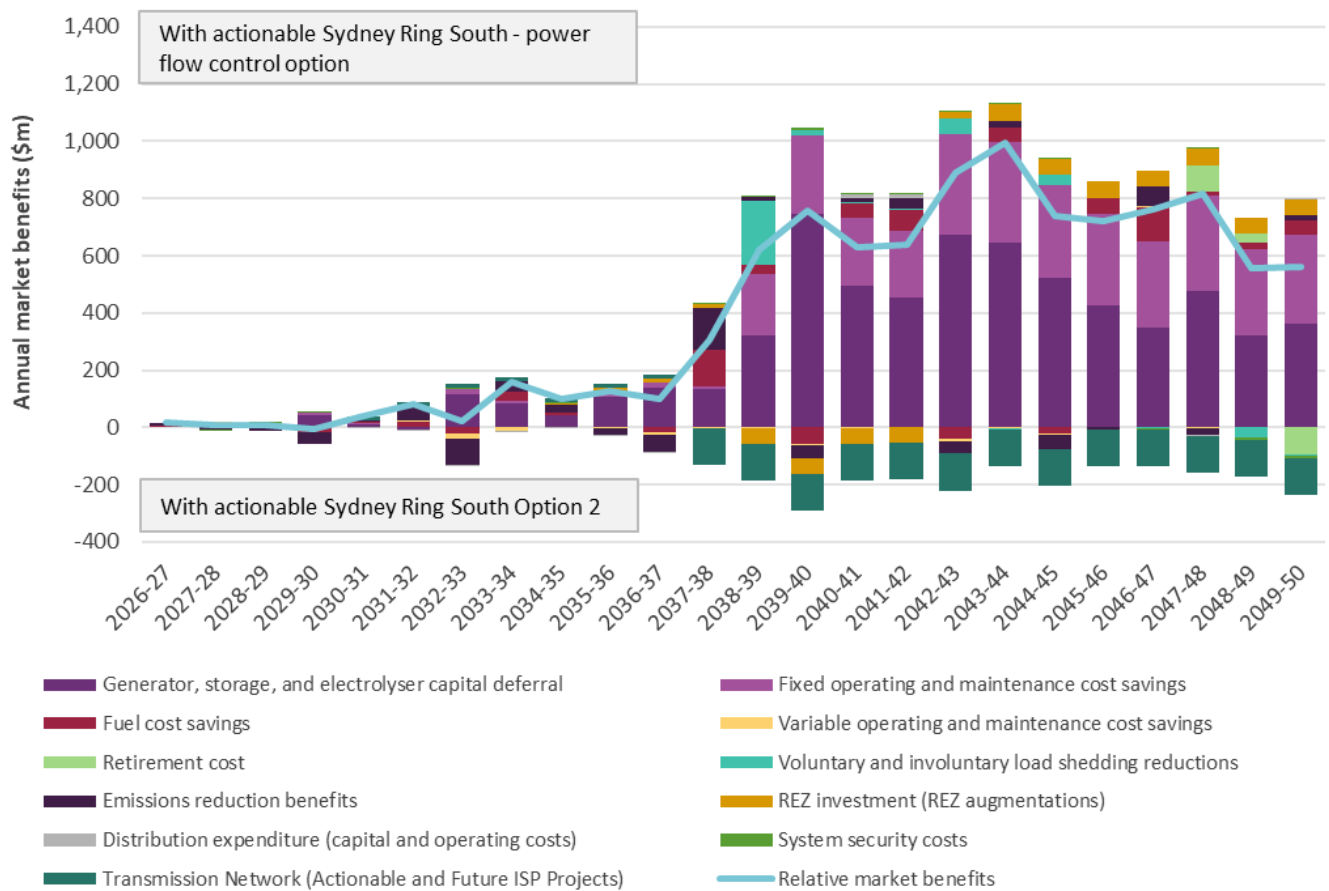
**Table 6** Relative market benefits of the least-cost DP compared with Alternative DP1 (which has Sydney Ring South Option 2 instead), Step Change

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	1,980
Fixed operating and maintenance cost savings	995
Fuel cost savings	156
Variable operating and maintenance cost savings	-30
Retirement cost	8
Voluntary and involuntary load shedding reductions	115
Emissions reduction benefits	2
REZ investment (REZ augmentations)	43
Distribution expenditure (capital and operating costs)	6
System security costs	20
<b>Gross market benefits</b>	<b>3,295</b>
Transmission Network (Actionable and Future ISP Projects)	-427
<b>Total net market benefits</b>	<b>2,868</b>

**Figure 6** Comparison of capacity with actionable Sydney Ring South power flow controller option and later 500 kV option compared with Sydney Ring South Option 2 in Step Change (at 2030-31)



**Figure 7 Annual relative market benefits of actionable Sydney Ring South power flow controller option and later 500 kV option compared with Sydney Ring South Option 2 in Step Change (at 2030-31)**



### Benefits of developing Sydney Ring South power flow controller option

The least-cost development path for *Step Change* has two Sydney Ring South augmentations – a power flow controller option in 2030-31 (which would progress it as an actionable project), and a larger 500 kV option (in two stages) in 2037-38. Alternative DP2 explores the impact of developing the 500 kV line earlier, at its earliest timing, instead of the power flow controller option.

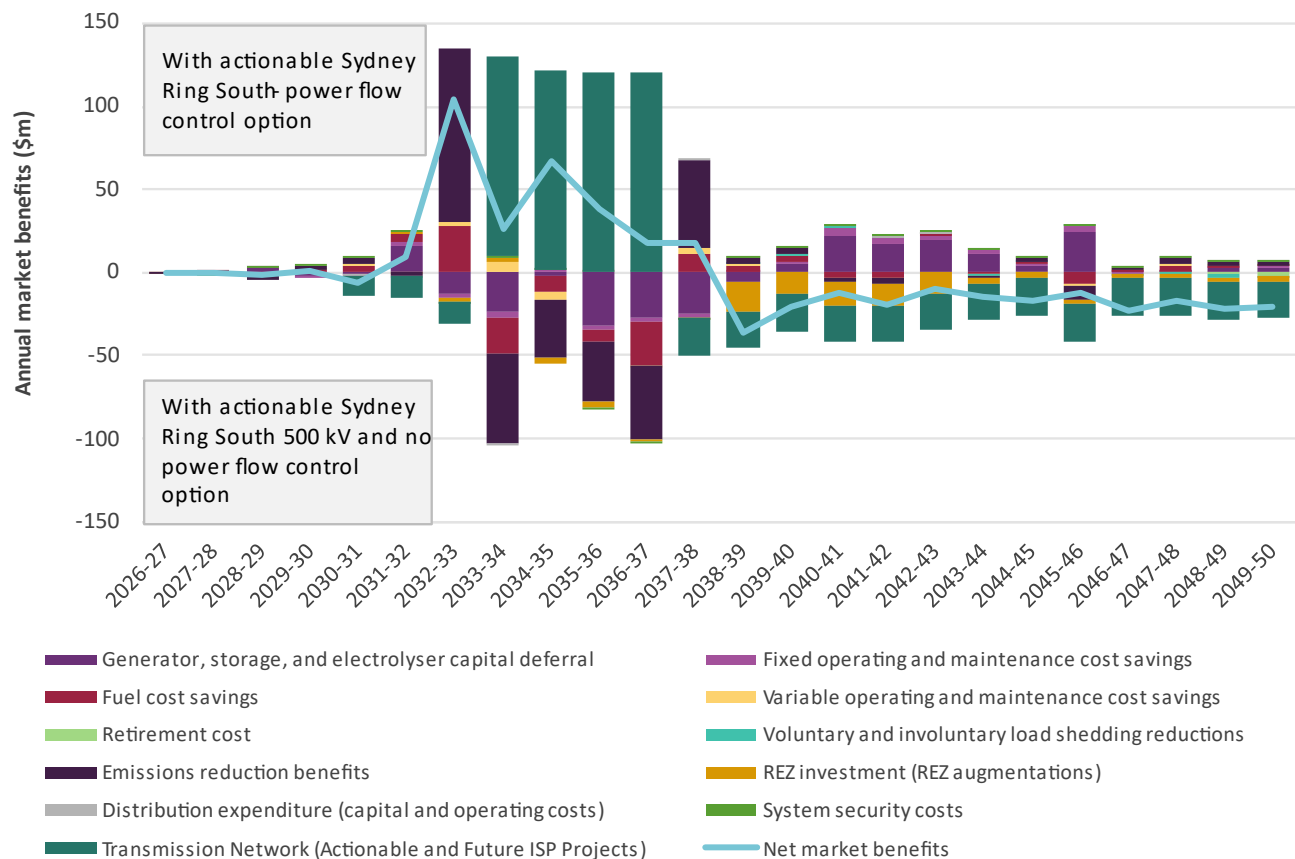
As shown in **Table 7** and **Figure 8**, developing the smaller option at its EISD instead of the larger option at its EISD (three years later) provides around \$80 million in net market benefits. While the larger option would deliver generator and storage capital deferral savings, it is a more costly development, and it is more marginal whether the transfer capability increase is sufficiently valuable if delivered earlier. As **Figure 8** shows, the slower earliest development of the 500 kV option in the least cost DP would also have fuel and emissions cost impacts. Given the net benefit of these options are similar, AEMO considers that Transgrid should continue to evaluate both options through the RIT-T.

The smaller option also delivers fuel cost savings and emission reduction benefits before delivery of the larger option, particularly in 2032-33, avoiding coal generation in Sydney, Newcastle and Wollongong sub-region and to a lesser extent Queensland.

**Table 7** Relative market benefits of the least-cost DP compared with Alternative DP2 (which has actionable Sydney Ring South – 500 kV option (Stages 1 and 2) instead), Step Change

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	-21
Fixed operating and maintenance cost savings	1
Fuel cost savings	-5
Variable operating and maintenance cost savings	4
Retirement cost	-1
Voluntary and involuntary load shedding reductions	0
Emissions reduction benefits	-1
REZ investment (REZ augmentations)	-33
Distribution expenditure (capital and operating costs)	1
System security costs	2
<b>Gross market benefits</b>	<b>-51</b>
Transmission Network (Actionable and Future ISP Projects)	132
<b>Total net market benefits</b>	<b>80</b>

**Figure 8** Annual relative market benefits of Sydney Ring South power flow controller option (at 2030-31) and Sydney Ring South – 500 kV option (Stages 1 and 2) (at 2033-34) in Step Change





### Benefits of expanding the network capacity of Central Highlands REZ

Tasmania will require additional renewable generation capacity to meet the state’s renewable energy target. The Waddamana to Palmerston transfer capability upgrade facilitates this by providing 555 MW of extra network capacity to support new generation in the region at a cost of \$240 million when delivered in 2030-31.

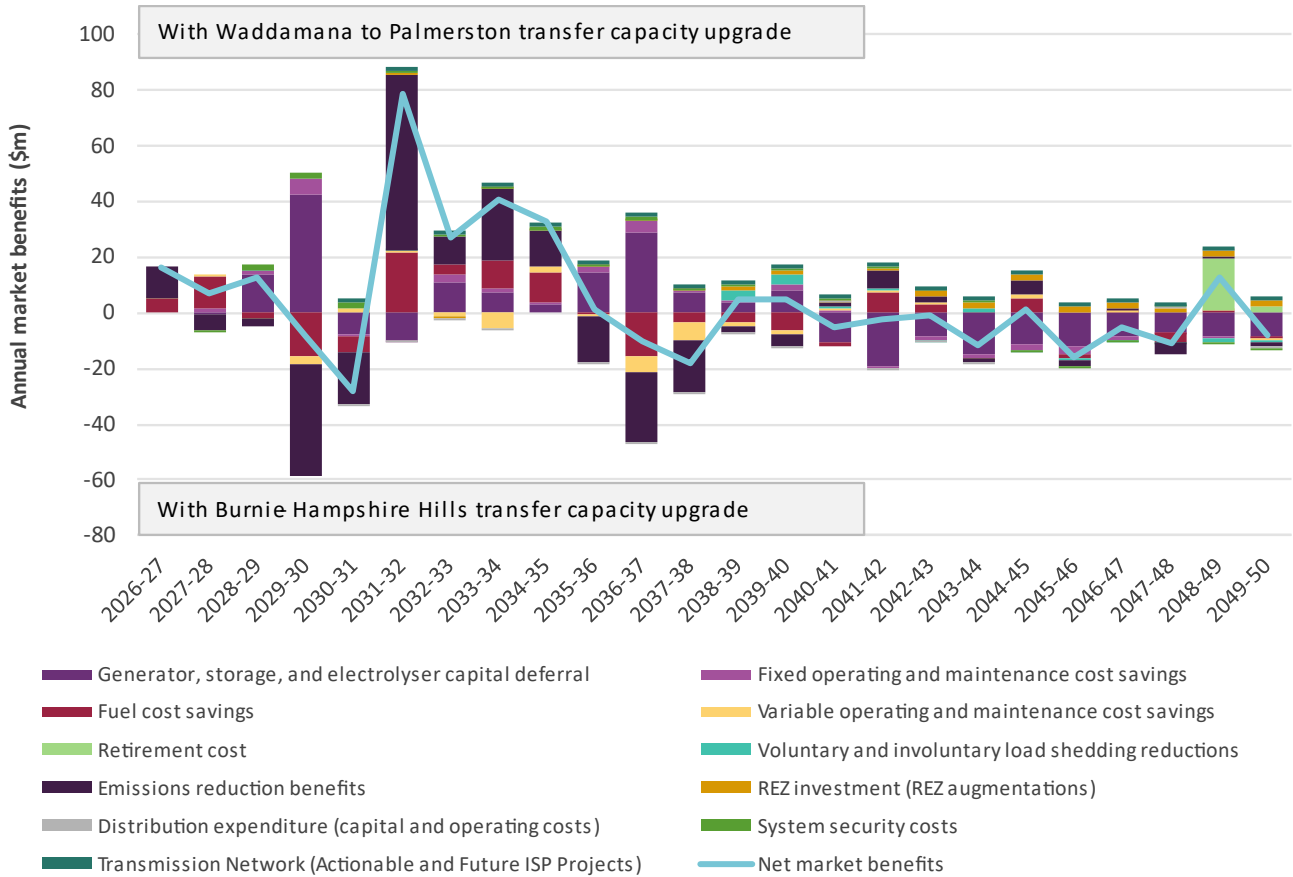
Alternative DP3 is an alternative REZ development that features the Burnie-Hampshire Hills transfer capacity upgrade in North West Tasmania that would provide an extra 800 MW of network renewable generation export capacity at a cost of \$268 million if delivered at its earliest timing in 2030-31.

**Figure 9** shows the relative market benefits of developing the Waddamana to Palmerston transfer capability upgrade (which upgrades the Central Highlands REZ) instead of the Burnie-Hampshire Hills transfer capacity upgrade (which upgrades the North-West Tasmania REZ). The \$89 million in relative market benefits primarily stem from being able to develop wind capacities in Central Highlands REZ at lower cost than in North-West Tasmania REZ.

**Table 8** Relative market benefits of the least-cost DP compared with Alternative DP3 (which has Burnie-Hampshire Hills transfer capacity upgrade instead), *Step Change*

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	39
Fixed operating and maintenance cost savings	11
Fuel cost savings	16
Variable operating and maintenance cost savings	-9
Retirement cost	4
Voluntary and involuntary load shedding reductions	3
Emissions reduction benefits	1
REZ investment (REZ augmentations)	6
Distribution expenditure (capital and operating costs)	-0
System security costs	8
<b>Gross market benefits</b>	<b>78</b>
Transmission Network (Actionable and Future ISP Projects)	10
<b>Total net market benefits</b>	<b>89</b>

**Figure 9 Annual relative market benefits of Waddamana to Palmerston transfer capability upgrade and Burnie-Hampshire hills transfer capability upgrade in Step Change (at 2030-31)**



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

**Table 9** 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<sup>22</sup>. 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 10** 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.

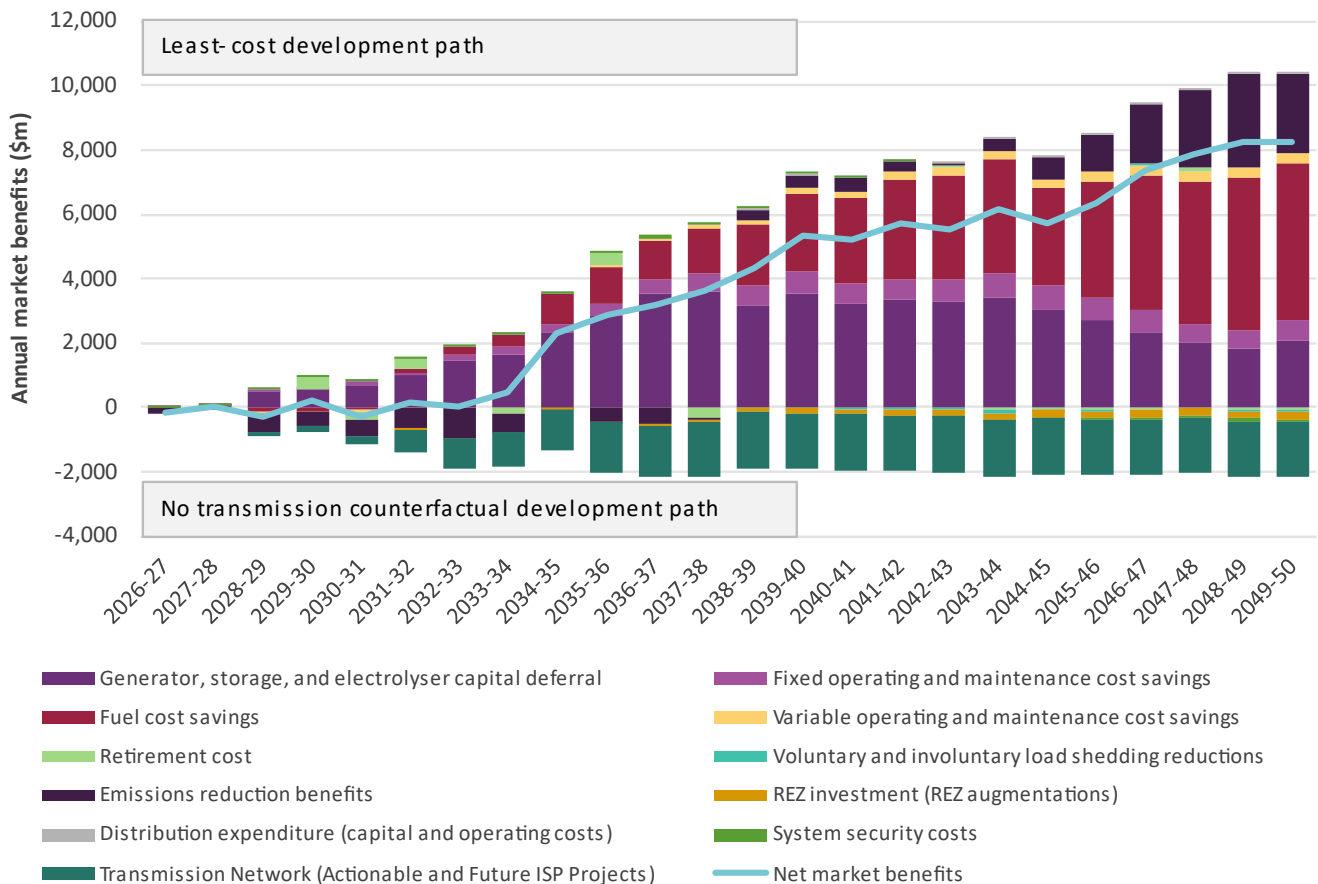
Under the 'no transmission' counterfactual DP, flexible gas, including using carbon capture storage, is required in the latter years to ensure energy supply can be met, while also meeting government policies, with lesser ability to develop renewable generation by upgrading the transmission network. To ensure that emissions targets can still be achieved, several black coal-fired generators in New South Wales and Queensland are retired earlier which results in up to 6 GW of wind capacity development being brought forward into existing REZs with available capacity. Up to 7 GW of additional utility-scale storage is required as well to provide firming capacity.

<sup>22</sup> Neither flow path nor REZ transmission augmentations are allowed in this counterfactual. This does not include connecting assets for new plants which will continue to connect to the existing network.

**Table 9 Net market benefits of the least-cost DP compared with the 'no transmission' counterfactual DP (which has no transmission development), Step Change**

Class of market benefit	Net market benefit (NPV, \$ million)
Generator and storage capital deferral	18,994
Fixed operating and maintenance cost savings	3,344
Fuel cost savings	13,234
Variable operating and maintenance cost savings	781
Retirement cost	177
Voluntary and involuntary load shedding reductions	-102
Emissions reduction benefits	78
REZ investment (REZ augmentations)	-756
Distribution expenditure (capital and operating costs)	59
System security costs	156
<b>Gross market benefits</b>	<b>35,965</b>
Transmission Network (Actionable and Future ISP Projects)	-10,486
<b>Total net market benefits</b>	<b>25,479</b>

**Figure 10 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 to strengthen the connection to the backbone network and 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 carbon-capture and storage to reduce carbon emissions. Development and operation of this flexible gas results in fuel cost increases and requires further gas system and carbon storage infrastructure development (although these are costs that are not included in the cost categories, or market benefits classes, of the CBA assessment). 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 not enough 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 is assumed to be lifted.

### A6.3.2 Least-cost development path for *Slower Growth*

The *Slower Growth* scenario 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 lesser need for network expansion, generation development, and storage development compared with the *Step Change* scenario, although the scenario still is designed to accommodate all eligible government policies.

**Table 10** presents the timings of the network development projects in the least-cost DP for *Slower Growth* and a subset of alternative DPs. The selection of alternative DPs shown below demonstrate the reasons the larger Queensland SuperGrid South project is identified as a future option (Alternative DP4).

**Table 10** Subset of development paths assessed in *Slower Growth*

Network option	EISD	Least-cost DP	Alternative DP4
Gladstone Project	2028-29	2028-29	2028-29
Auburn River Switching Station <sup>A</sup>	2031-32	2041-42	2041-42
Queensland SuperGrid South <sup>A</sup>	2031-32	2041-42	
Queensland – New South Wales Interconnector (QNI) Connect	2033-34 <sup>B</sup>		
New England REZ Network Infrastructure Project (REZ option)	2032-33		
New England REZ Network Infrastructure Project (Flow path option)	2032-33		
Sydney Ring North (Hunter Transmission Project 1.0)	2029-30	2029-30	2029-30
Sydney Ring South Option 2	2030-31		
Sydney Ring South power flow controller option	2030-31	2030-31	2030-31
Sydney Ring South - 500 kV option (Stage 1)	2033-34		
Sydney Ring South - 500 kV option (Stage 2)	2033-34		
Dubbo Distribution Project	2030-31		
Switching Station Near Wondalga	2029-30	2029-30	2029-30
Victoria – New South Wales Interconnector West (VNI West)	2031-32	2031-32	2031-32
Western Victoria Reinforcement program	2028-29	2040-41	2040-41
South West Victoria expansion program	2033-34		
Gippsland Offshore Wind Transmission Stage 1	2031-32	2031-32	2031-32
Gippsland Offshore Wind Transmission Stage 2 (Phase 1)	2033-34	2033-34	2033-34
Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	2038-39	2038-39	2038-39
Eastern Victoria Reinforcement program Option 1	2031-32		
Eastern Victoria Reinforcement program Option 2	2031-32	2038-39	2038-39
Heywood Interconnector Upgrade	2031-32		
Northern Transmission Project	2029-30		
SESA-CSA Transmission Upgrade	2029-30		
Project Marinus Stage 2	2034-35	2034-35	2034-35
Burnie-Hampshire Hills transfer capacity upgrade (North West Tasmania REZ)	2030-31		
Waddamana to Palmerston transfer capacity upgrade (Central Highlands REZ)	2030-31	2030-31	2030-31
<b>Reduction in net market benefits (\$ million) compared with the least-cost DP</b>		-	<b>404</b>

A. Part of the Central Queensland to Southern Queensland Expansion project.

B. For QNI, proponent timing is different than EISD. AEMO has tested the optimal timing considering the proponent’s timing.

**Note:** Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period.

## Benefits of Queensland SuperGrid South as a future project

Queensland SuperGrid South is a new 500 kV line allowing for additional transfer capacity (3,150 MW from Southern Queensland to Central Queensland, and 1,900 MW in the reverse direction) of the flow path between the two sub-regions at a cost of \$ 4,280 million in 2041-42. It is the second part to the Central Queensland to Southern Queensland Expansion project, with the first part being the Auburn River switching station.

Delivery of Queensland SuperGrid South is optimal in 2041-42 in the least-cost DP for *Slower Growth*. The benefit of augmentation can be assessed via comparison with Alternative DP4, which does not feature the project from the scenario's least-cost DP.

The project delivers \$404 million in net market benefits if delivered in 2041-42, which come mainly from generator and storage capital deferral, followed by fuel cost savings. The main benefit of the project in the scenario is accessing Borumba Pumped Hydro (which is developed in 2034-35) and unlocking around 1.9 GW from 2042-43 of additional utility-scale solar capacity in South Queensland.

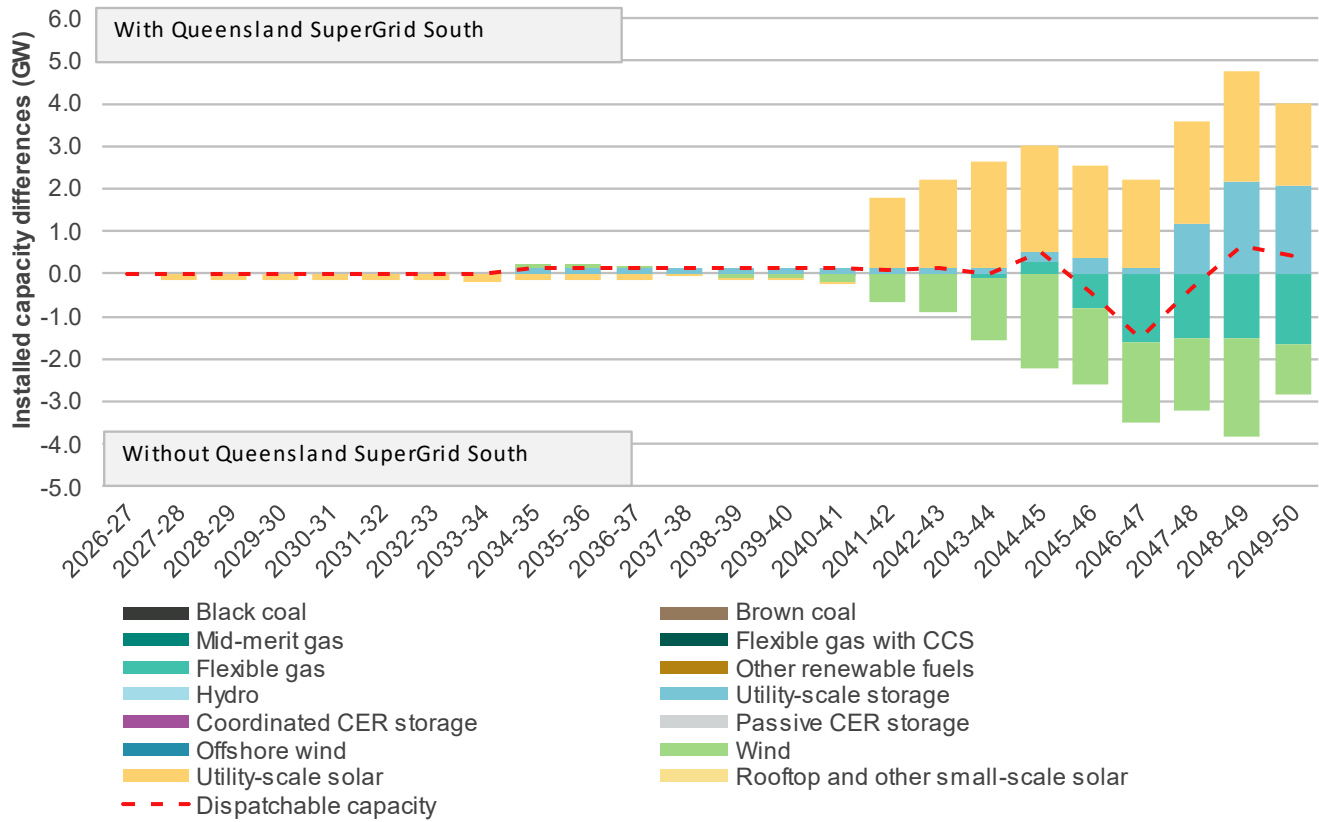
In *Slower Growth*, the additional capacity provided by the augmentation is never fully utilised in either direction, although there is an increase in flows towards Central Queensland, and greater utilisation of the Gladstone Project as access to Borumba Pumped Hydro enables the pumped hydro project to soak up utility-scale solar generation and support remaining industry in Gladstone.

Without the augmentation, nearly 1.5 GW of more expensive wind capacity is required by 2043-44 in Central Queensland and North Queensland. From 2046-47, the project also defers 1.7 GW of additional flexible gas in Central Queensland and Gladstone sub-regions. The project also avoids flexible generation in South Queensland which drives fuel cost savings and emission reduction benefits.

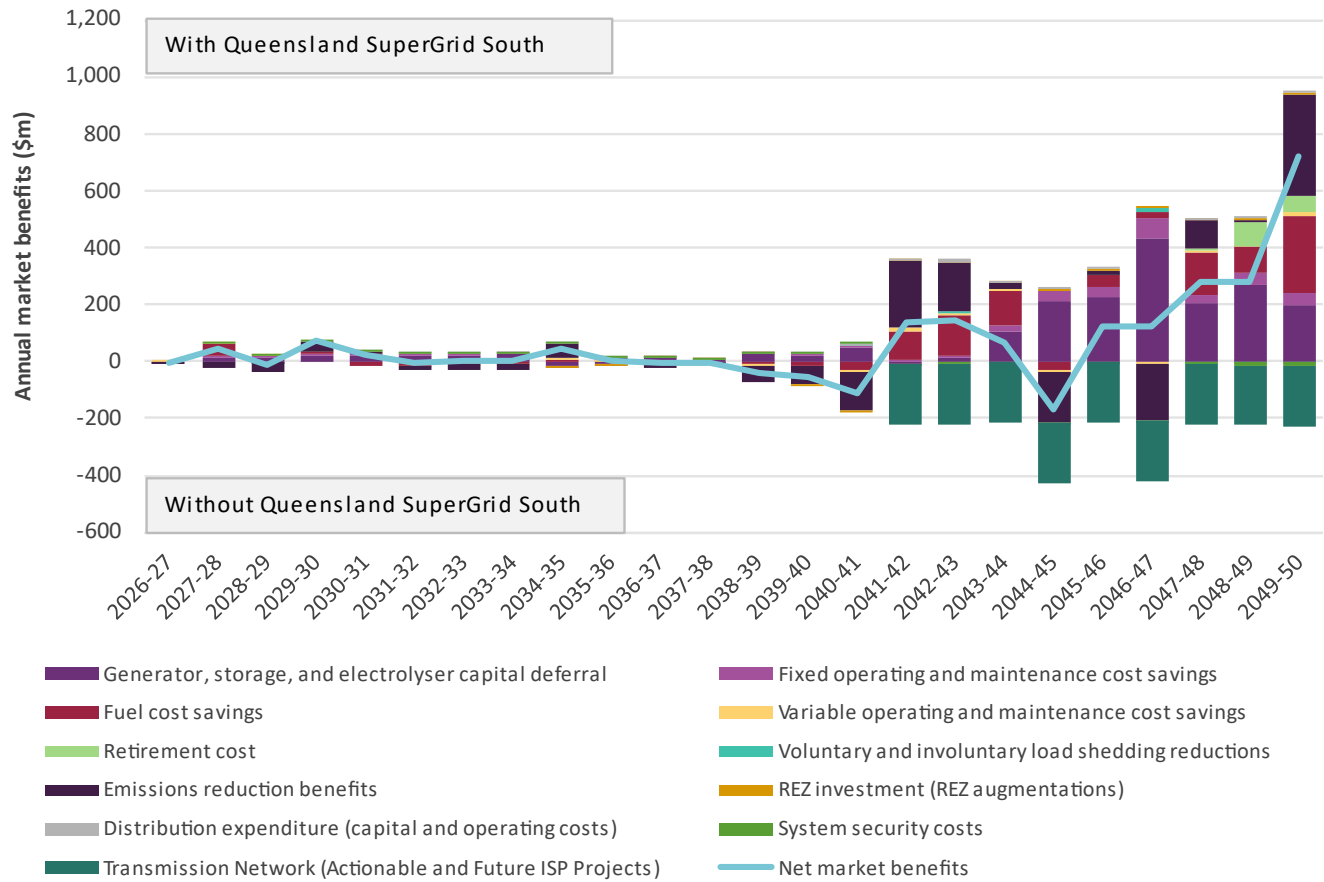
**Table 11 Relative market benefits of the least-cost DP compared with Alternative DP4 (which removes Queensland SuperGrid South), *Slower Growth***

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	503
Fixed operating and maintenance cost savings	81
Fuel cost savings	213
Variable operating and maintenance cost savings	10
Retirement cost	27
Voluntary and involuntary load shedding reductions	6
Emissions reduction benefits	17
REZ investment (REZ augmentations)	7
Distribution expenditure (capital and operating costs)	12
System security costs	-2
<b>Gross market benefits</b>	<b>874</b>
Transmission Network (Actionable and Future ISP Projects)	-470
<b>Total net market benefits</b>	<b>404</b>

**Figure 11 Comparison of capacity between the least-cost DP and Alternative DP4 in Slower Growth (with and without Queensland SuperGrid South in 2041-42)**



**Figure 12 Annual relative market benefits of SuperGrid South in Slower Growth (2041-42 and never)**



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

Table 12 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<sup>23</sup>. The main sources of benefits are capital deferral in generation, storage, and electrolyser assets, fuel cost savings, and emission reduction benefits. Although the least-cost development path develops various transmission developments before 2034-35, the primary benefits to defer more costly generation and storage alternatives accumulate most significantly after 2034-35. Across the entire outlook period, transmission investments also accrue material benefits from fuel cost savings and emission reduction benefits.

<sup>23</sup> 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.

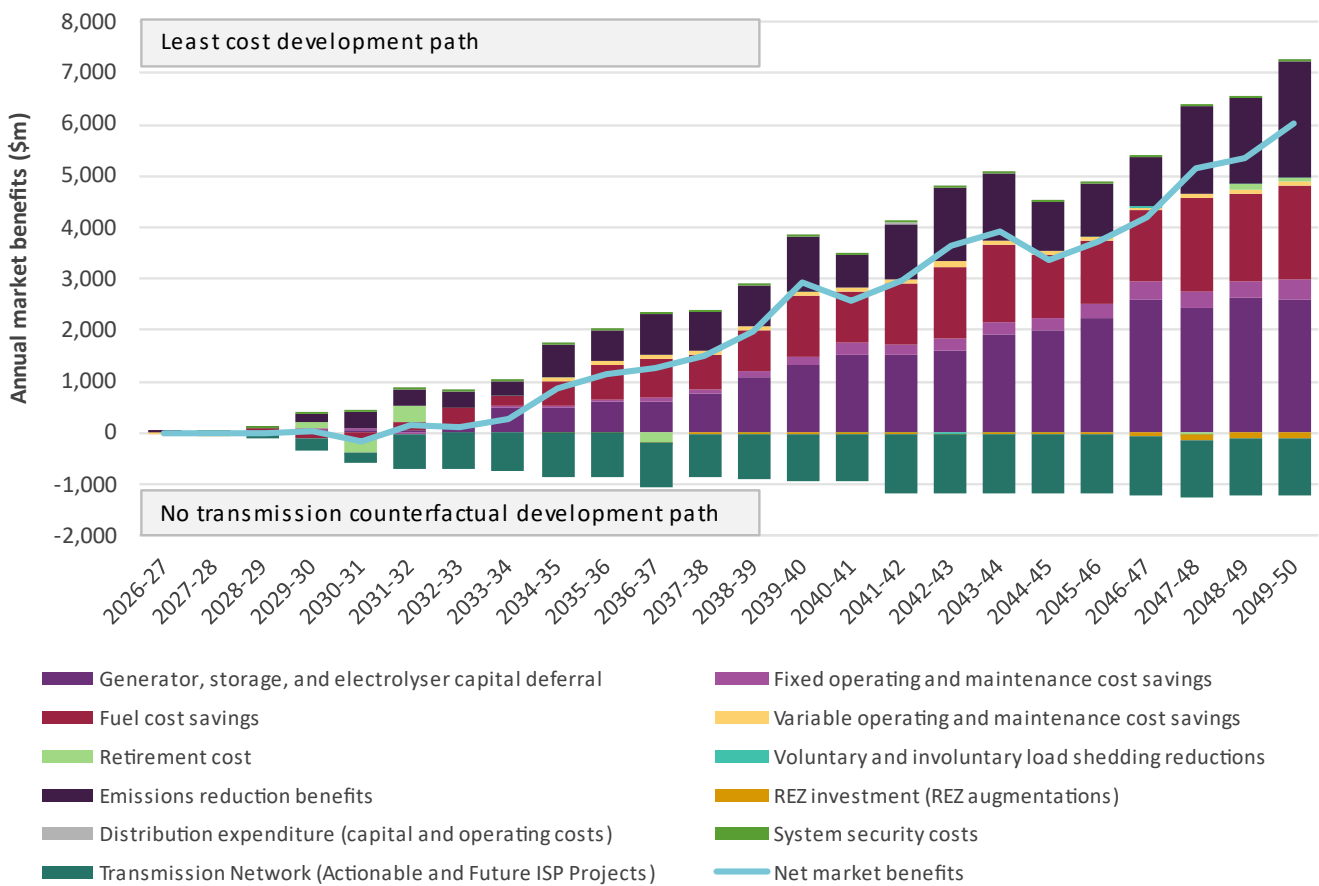
**Table 12 Net market benefits of the least-cost DP compared with the ‘no transmission’ counterfactual DP (which has no major transmission development), *Slower Growth***

Class of market benefit	Net market benefit (NPV, \$ million)
Generator and storage capital deferral	7,730
Fixed operating and maintenance cost savings	992
Fuel cost savings	5,662
Variable operating and maintenance cost savings	437
Retirement cost	70
Voluntary and involuntary load shedding reductions	1
Emissions reduction benefits	5,970
REZ investment (REZ augmentations)	-146
Distribution expenditure (capital and operating costs)	18
System security costs	157
<b>Gross market benefits</b>	<b>20,890</b>
Transmission Network (Actionable and Future ISP Projects)	-6,685
<b>Total net market benefits</b>	<b>14,205</b>

The least-cost development path maintains higher levels of coal capacity until the mid-2030s. Instead, the ‘no transmission’ counterfactual DP requires more significant development of flexible gas (mostly in Greater Melbourne and Geelong sub-region) and wind capacity which is developed across all states but particularly in Victoria and Queensland. 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 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 demonstrated in **Figure 13**.

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 supply limitations. AEMO does not consider this credible, hence the gas supply limit applied to flexible gas development Gladstone Grid was assumed to be lifted.

**Figure 13 Net market benefits of the least-cost development path relative to the 'no transmission' counterfactual DP in Slower Growth**



### A6.3.3 Least-cost development path for Accelerated Transition

The *Accelerated Transition* scenario 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 the *Step Change* scenario.

**Table 13** presents the timing of various transmission expansion options in the least-cost DP for *Accelerated Transition* and in a subset of alternative DPs. When contrasted with the least-cost DP, the alternative DPs selected demonstrate:

- why the delivery of Dubbo Distribution Project would provide additional benefits in this scenario (Alternative DP5),
- why the expansion of the South East South Australia (SESA) - Central South Australia (CSA) flow path is required (Alternative DP6), and
- the impact of alternative augmentations for Eastern Victoria Reinforcement program (Alternative DP7).

**Table 13** Subset of development paths assessed in Accelerated Transition

Network option	EISD	Least-cost DP	Alternative DP5	Alternative DP6	Alternative DP7
Gladstone Project	2028-29	2028-29	2028-29	2028-29	2028-29
Auburn River Switching Station <sup>A</sup>	2031-32	2034-35	2034-35	2034-35	2034-35
Queensland SuperGrid South <sup>A</sup>	2031-32	2034-35	2034-35	2034-35	2034-35
Queensland – New South Wales Interconnector (QNI) Connect	2033-34 <sup>B</sup>	2033-34	2033-34	2033-34	2033-34
New England REZ Network Infrastructure Project (REZ option)	2032-33	2032-33	2032-33	2032-33	2032-33
New England REZ Network Infrastructure Project (Flow path option)	2032-33	2032-33	2032-33	2032-33	2032-33
Sydney Ring North (Hunter Transmission Project 1.0)	2029-30	2029-30	2029-30	2029-30	2029-30
Sydney Ring South Option 2	2030-31				
Sydney Ring South power flow controller option	2030-31	2030-31	2030-31	2030-31	2030-31
Sydney Ring South - 500 kV option (Stage 1)	2033-34	2033-34	2033-34	2033-34	2033-34
Sydney Ring South - 500 kV option (Stage 2)	2033-34	2033-34	2033-34	2033-34	2033-34
Dubbo Distribution Project	2030-31	2030-31		2030-31	2030-31
Switching Station Near Wondalga	2029-30	2029-30	2029-30	2029-30	2029-30
Victoria – New South Wales Interconnector West (VNI West)	2031-32	2031-32	2031-32	2031-32	2031-32
Western Victoria Reinforcement program	2028-29	2028-29	2028-29	2028-29	2028-29
South West Victoria expansion program	2033-34	2035-36	2035-36	2035-36	2035-36
Gippsland Offshore Wind Transmission Stage 1	2031-32	2031-32	2031-32	2031-32	2031-32
Gippsland Offshore Wind Transmission Stage 2 (Phase 1)	2033-34	2033-34	2033-34	2033-34	2033-34
Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	2038-39	2038-39	2038-39	2038-39	2038-39
Eastern Victoria Reinforcement program Option 1	2031-32	2031-32	2031-32	2031-32	
Eastern Victoria Reinforcement program Option 2	2031-32				2031-32
Heywood Interconnector Upgrade	2031-32	2045-46	2045-46	2045-46	2045-46
Northern Transmission Project	2029-30				
SESA-CSA Transmission Upgrade	2029-30	2037-38	2037-38		2037-38
Project Marinus Stage 2	2034-35	2034-35	2034-35	2034-35	2034-35
Burnie-Hampshire Hills transfer capacity upgrade (North West Tasmania REZ)	2030-31				
Waddamana to Palmerston transfer capacity upgrade (Central Highlands REZ)	2030-31	2030-31	2030-31	2030-31	2030-31
<b>Reduction in net market benefits (\$ million) compared with the least-cost DP</b>		-	<b>133</b>	<b>21</b>	<b>102</b>

A. Part of the Central Queensland to Southern Queensland Expansion project.

B. For QNI, proponent timing is different than EISD. AEMO has tested the optimal timing considering the proponent’s timing.

Note: Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period.

## Benefits of developing the Dubbo Distribution Project in Accelerated Transition

In the Draft 2026 ISP, AEMO is including for the first time several distribution REZs, which would enable connection of utility-scale resources within specific locations of the distribution network.

In *Accelerated Transition*'s least-cost development path, the Dubbo Distribution Project is developed at its EISD of 2030-31, and this is compared against Alternative DP5, which excludes the project while keeping all other projects equal to the least-cost development path.

**Table 14** indicates that building the Dubbo Distribution Project delivers \$133 million in net market benefits in *Accelerated Transition*. The network capacity provided by Dubbo Distribution Project is utilised through the development of 1.1 GW of utility-scale solar and wind by 2032-33, increasing to 1.8 GW by 2042-43. In this scenario, other REZs would need greater development in New South Wales if the distribution project did not proceed, which would increase total costs.

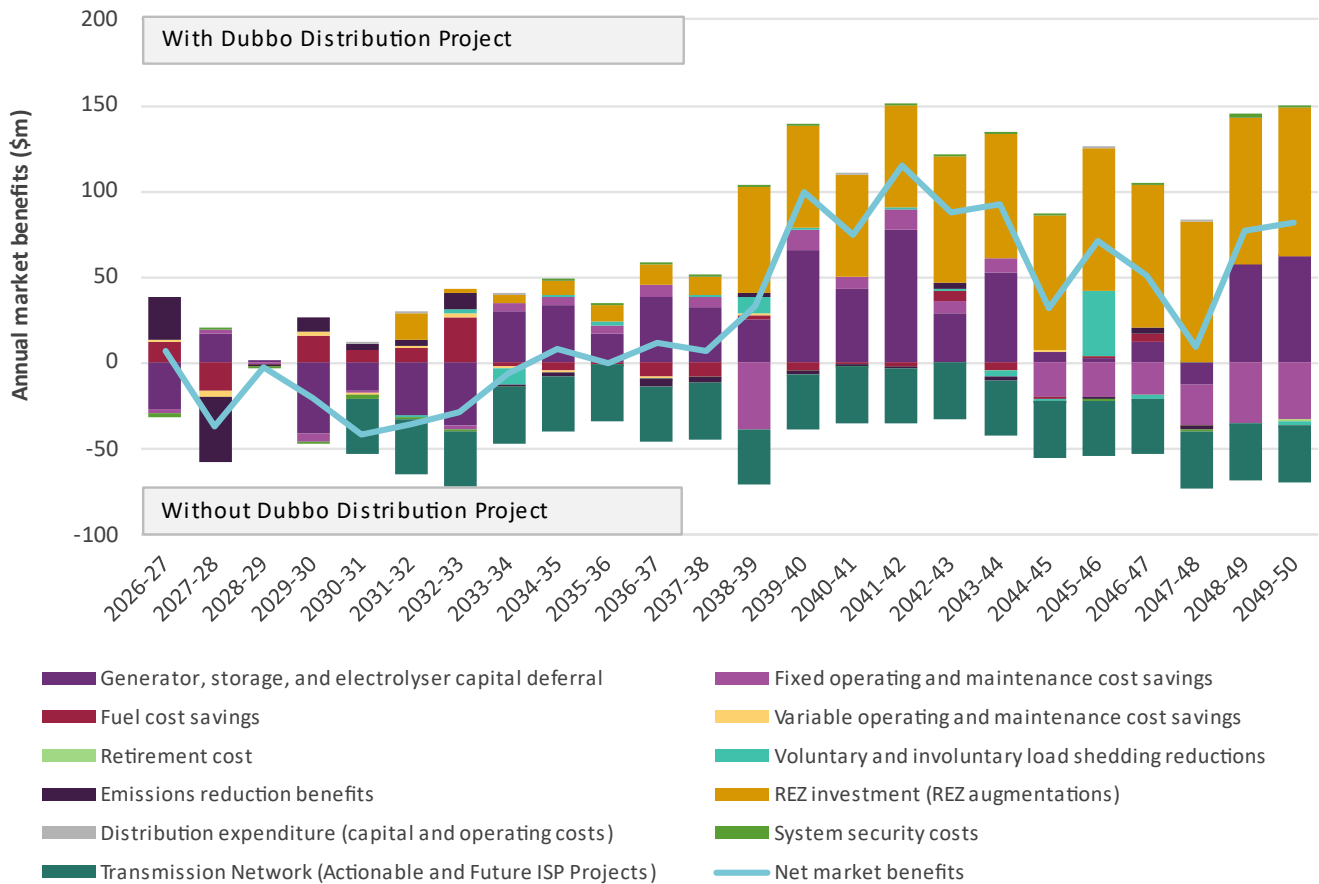
In particular, the development of the distribution project would avoid 630 MW of utility-scale solar capacity and additional transmission augmentation are required in Hunter-Central Coast from 2032-33 onwards, and 280 MW of additional wind capacity and further transmission augmentation are also required in Central-West Orana from 2033-34 onwards.

It is worth noting that the ISP framework does not apply to distribution augmentations, therefore, the Dubbo Distribution Project may progress through the normal Regulatory Investment Test for Distribution (RIT-D) or the NSW Electricity Infrastructure Investment (EII) Act.

**Table 14 Relative market benefits of the least-cost DP compared with Alternative DP5 (which removes Dubbo Distribution Project), *Accelerated Transition***

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	105
Fixed operating and maintenance cost savings	-25
Fuel cost savings	25
Variable operating and maintenance cost savings	1
Retirement cost	-0
Voluntary and involuntary load shedding reductions	9
Emissions reduction benefits	0
REZ investment (REZ augmentations)	267
Distribution expenditure (capital and operating costs)	0
System security costs	-3
<b>Gross market benefits</b>	<b>379</b>
Transmission Network (Actionable and Future ISP Projects)	-247
<b>Total net market benefits</b>	<b>133</b>

**Figure 14 Annual relative market benefits of Dubbo Distribution Project in Accelerated Transition**



### Benefits of the SESA-CSA transmission upgrade

The SESA-CSA flow path connects the load centres near Adelaide to the South East South Australia sub-region. The existing flow path has a maximum transfer capability of 790 MW during peak demand and summer typical periods and 820 MW during winter. The augmentation option for this flow path would increase its transfer capacity by 120 MW at a cost of \$85 million if delivered at its EISD of 2029-30 by performing upgrades to the Tungkillo – Tailem Bend line. The key benefit of this upgrade would be improved reliability of supply to the load centres near Adelaide from SESA developments and Victoria via the Heywood Interconnector. In the least-cost DP for *Accelerated Transition*, this SESA-CSA flow path upgrade is most economical if delivered in 2037-38.

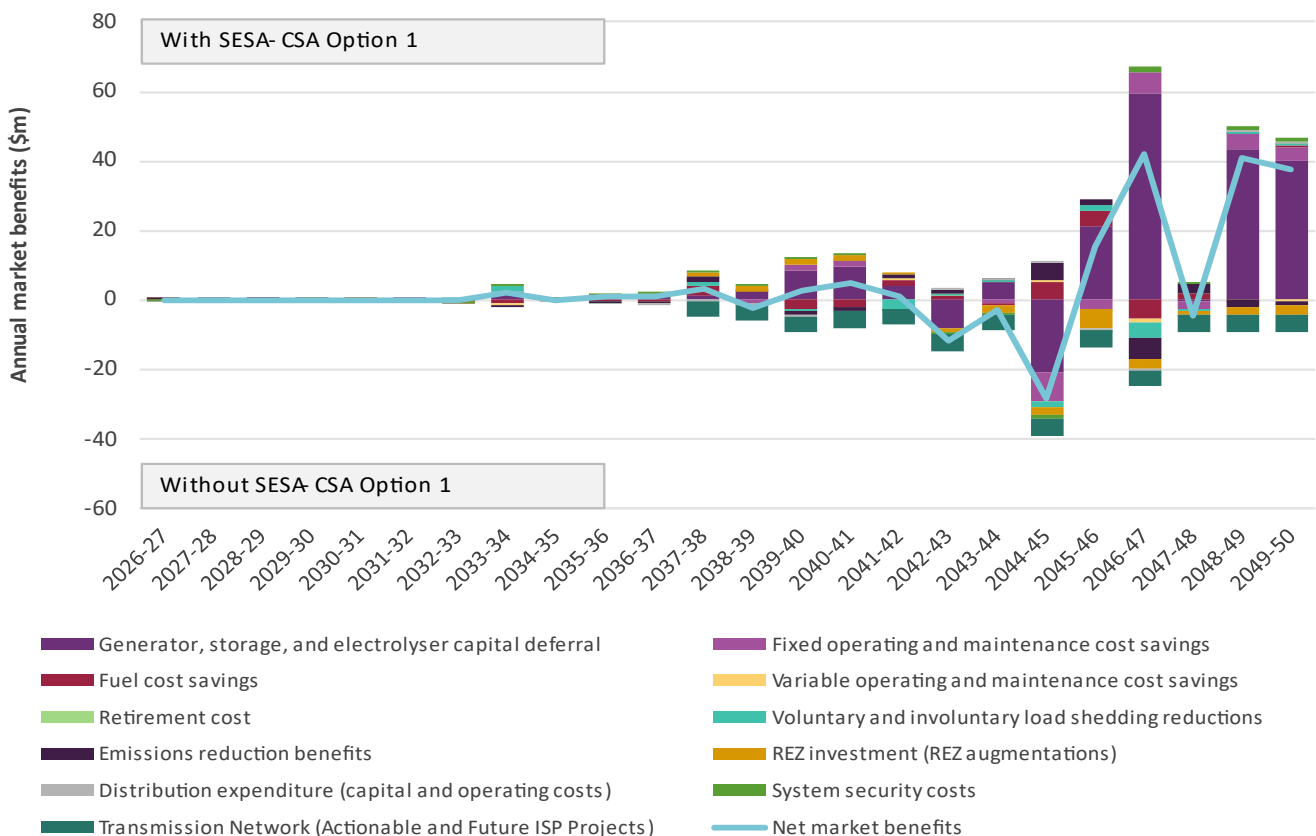
Comparison of Alternative DP6 and the least-cost DP, which isolates the project from other transmission project impacts, shows that delivering the SESA-CSA transmission upgrade under the *Accelerated Transition* scenario results in a relative market benefit of \$21 million, as shown in **Table 15**.

**Table 15** Relative market benefits of the least-cost DP compared with Alternative DP6 (which removes SESA-CSA Option 1), Accelerated Transition

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	39
Fixed operating and maintenance cost savings	1
Fuel cost savings	1
Variable operating and maintenance cost savings	-0
Retirement cost	0
Voluntary and involuntary load shedding reductions	0
Emissions reduction benefits	0
REZ investment (REZ augmentations)	-2
Distribution expenditure (capital and operating costs)	-0
System security costs	0
<b>Gross market benefits</b>	<b>38</b>
Transmission Network (Actionable and Future ISP Projects)	-17
<b>Total net market benefits</b>	<b>21</b>

Building this option in 2037-38 allows for small amounts of wind capacity to be avoided across Central South Australia and Northern South Australia sub-regions by developing wind capacity in South East South Australia sub-region and importing from Victoria.

**Figure 15** Annual relative market benefits of SESA-CSA Option 1 in Accelerated Transition (in 2037-38)



## Benefits of developing Eastern Victoria Reinforcement program Option 1 over Option 2

The Eastern Victoria Reinforcement program is an augmentation of transfer capacity into the Greater Melbourne and Geelong (MEL) sub-region from South-East Victoria (SEV) sub-regions. Two potential mutually exclusive options were identified for *Accelerated Transition*:

- a smaller Option 1 which provides a higher net market benefits if delivered at an actionable timing in *Accelerated Transition* by providing 1,000 MW additional transfer capacity into the MEL sub-region, and
- a larger and more expensive Option 2 with a transfer capacity increase of 2,700 MW, which is preferred in *Step Change* and *Slower Growth* at a non-actionable delivery timing of 2033-34 and 2038-39, respectively.

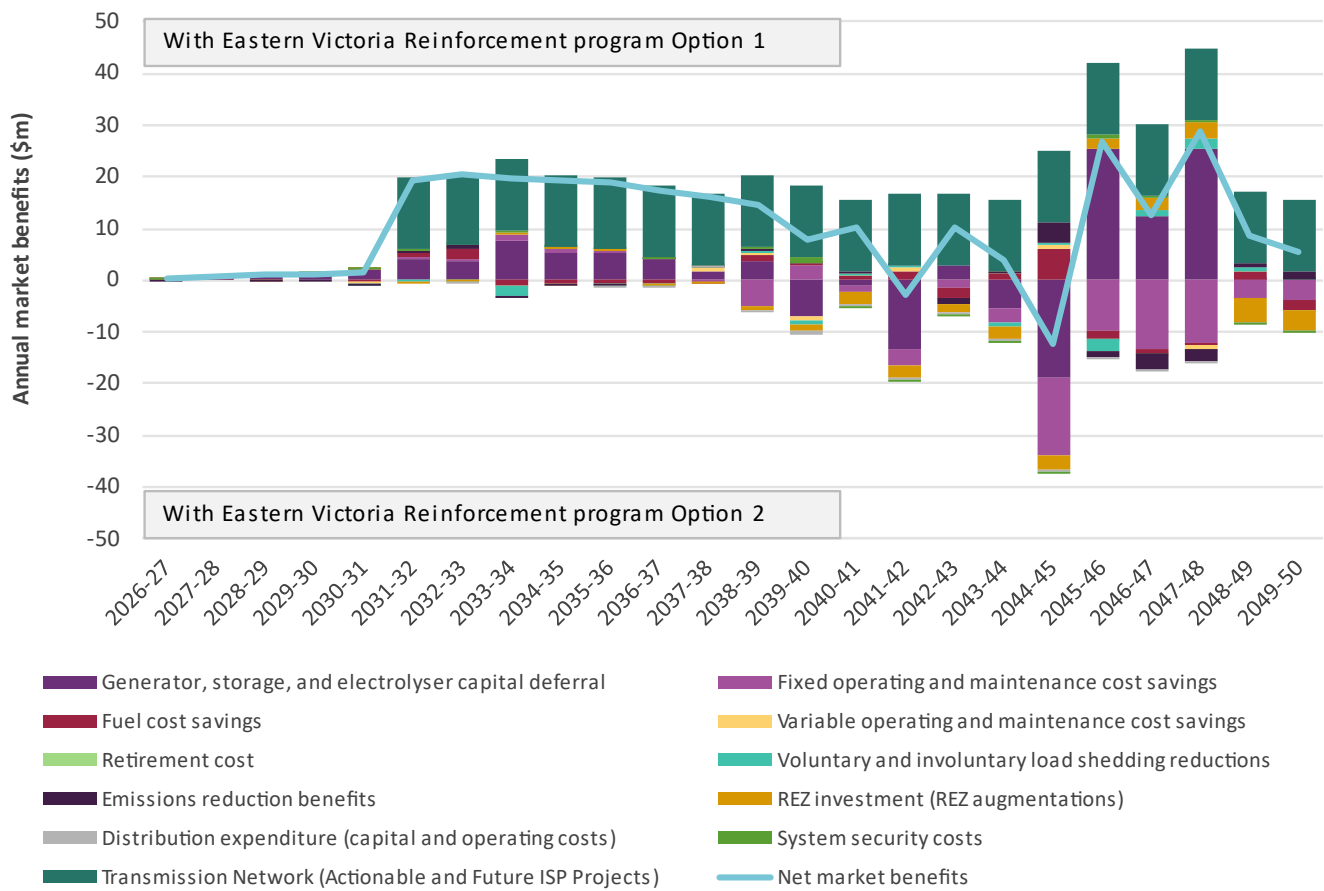
An alternative DP (Alternative DP7) which features Option 2 in 2031-32 instead of Option 1 was used to compare the net benefits of the two options. The additional 1,700 MW of transfer capacity into the MEL sub-region that the larger option provides over the smaller option is not utilised at all until 2038-39; this means there are negligible gross benefits over this period from developing the larger option.

Over the period to 2049-50, the only benefit of significance arising from the larger option is in fixed operating and maintenance cost savings totalling \$15 million. This comes from the deferral of small amounts of additional offshore wind (which has a much higher maintenance cost relative to other technologies) and utility-scale storage that are required in Victoria and New South Wales in the 2040s if the smaller option is developed. As shown in **Table 16**, however, this is insufficient to offset the additional cost of the larger option – that is, Option 1 is preferred in the least-cost DP for *Accelerated Transition*.

**Table 16** Relative market benefits of the least-cost DP (with Eastern Victoria Reinforcement program Option 1) compared with Alternative DP7 (which has Eastern Victoria Reinforcement program Option 2 instead), *Accelerated Transition*

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	23
Fixed operating and maintenance cost savings	-15
Fuel cost savings	2
Variable operating and maintenance cost savings	0
Retirement cost	-0
Voluntary and involuntary load shedding reductions	-1
Emissions reduction benefits	0
REZ investment (REZ augmentations)	-3
Distribution expenditure (capital and operating costs)	-1
System security costs	1
<b>Gross market benefits</b>	<b>6</b>
Transmission Network (Actionable and Future ISP Projects)	96
<b>Total net market benefits</b>	<b>102</b>

**Figure 16** Annual relative market benefits of Reinforcement program Option 1 compared to Eastern Victoria Reinforcement program Option 2 in Accelerated Transition



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

Table 17 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 \$34.3 billion.

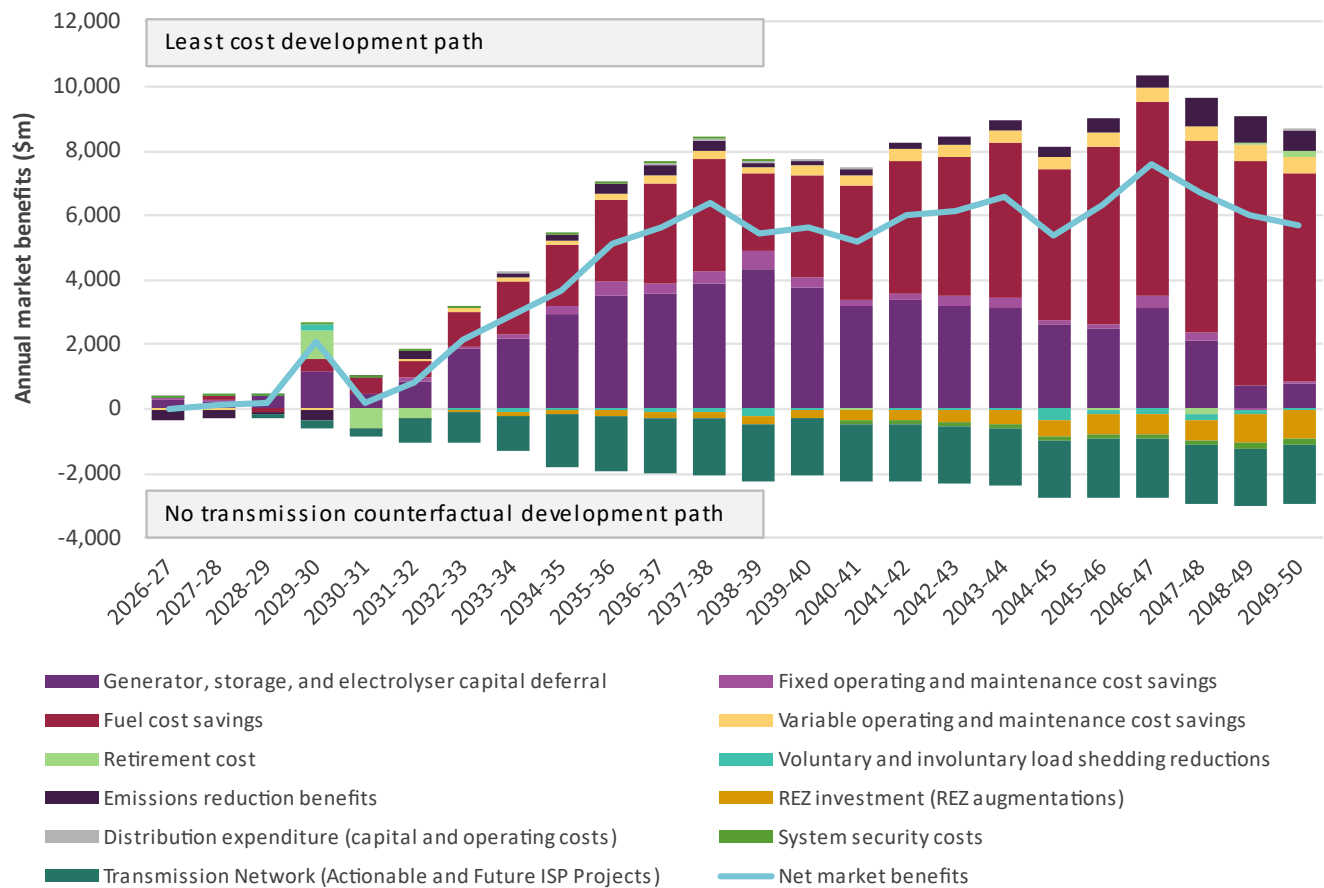
**Table 17** Net market benefits of the least-cost DP compared with the ‘no transmission’ counterfactual DP (which has no major transmission development), *Accelerated Transition*

Class of market benefit	Net market benefit (NPV, \$ million)
Generator and storage capital deferral	20,839
Fixed operating and maintenance cost savings	1,713
Fuel cost savings	22,364
Variable operating and maintenance cost savings	1,761
Retirement cost	89
Voluntary and involuntary load shedding reductions	-413
Emissions reduction benefits	1,032
REZ investment (REZ augmentations)	-1,937
Distribution expenditure (capital and operating costs)	8
System security costs	-135
<b>Gross market benefits</b>	<b>45,320</b>
Transmission Network (Actionable and Future ISP Projects)	-11,009
<b>Total net market benefits</b>	<b>34,311</b>

**Figure 17** 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 generator capital investment. Without transmission investment, the cost of operating the NEM with this scenario’s limited carbon budget is also greater without expanded transmission given the reduced capability to develop renewable energy in REZs. To compensate for this, the ‘no transmission’ counterfactual DP brings forward coal retirements (and the cost of these closures).

To continue to supply a growing NEM with limited renewable generation options, the ‘no transmission’ counterfactual DP starts to invest in flexible gas with carbon capture and storage (CCS) from 2032-33. This increases capital costs and fuel costs in the ‘no transmission’ counterfactual DP. Some additional other distributed storage is also required, and broader development of Australia’s offshore wind potential (beyond the Victorian Offshore Wind Target), where the network at point of onshore connection can accommodate the additional capacity.

**Figure 17 Net market benefits of the least-cost DP relative to the 'no transmission' counterfactual DP in Accelerated Transition**



With more limited development of renewable capacity due to the more 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 is not enough 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.

### A6.3.4 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.

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

A comparison of the least-cost DPs for each scenario by which projects are actionable and their respective timings is shown in Table 18.

**Table 18 Comparing the least-cost DPs between scenarios**

Network option	EISD	Slower Growth	Step Change	Accelerated Transition
Gladstone Project	2028-29	2028-29	2028-29	2028-29
Auburn River Switching Station <sup>A</sup>	2031-32	2041-42	2033-34	2034-35
Queensland SuperGrid South <sup>A</sup>	2031-32	2041-42	2035-36	2034-35
Queensland – New South Wales Interconnector (QNI) Connect	2033-34 <sup>B</sup>		2033-34	2033-34
New England REZ Network Infrastructure Project (REZ option)	2032-33		2032-33	2032-33
New England REZ Network Infrastructure Project (Flow path option)	2032-33		2032-33	2032-33
Sydney Ring North (Hunter Transmission Project 1.0)	2029-30	2029-30	2029-30	2029-30
Sydney Ring South power flow controller option	2030-31	2030-31	2030-31	2030-31
Sydney Ring South - 500 kV option (Stage 1)	2033-34		2037-38	2033-34
Sydney Ring South - 500 kV option (Stage 2)	2033-34		2037-38	2033-34
Dubbo Distribution Project	2030-31		2032-33	2030-31
Switching Station Near Wondalga	2029-30	2029-30	2031-32	2029-30
Victoria – New South Wales Interconnector West (VNI West)	2031-32	2031-32	2031-32	2031-32
Western Victoria Reinforcement program	2028-29	2040-41	2028-29	2028-29
South West Victoria expansion program	2033-34		2035-36	2035-36
Gippsland Offshore Wind Transmission Stage 1	2031-32	2031-32	2031-32	2031-32
Gippsland Offshore Wind Transmission Stage 2 (Phase 1)	2033-34	2033-34	2033-34	2033-34
Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	2038-39	2038-39	2038-39	2038-39
Eastern Victoria Reinforcement program Option 1	2031-32			2031-32
Eastern Victoria Reinforcement program Option 2	2031-32	2033-34	2033-34	
Heywood Interconnector Upgrade	2031-32			2045-46
SESA-CSA Transmission Upgrade	2029-30			2037-38
Project Marinus Stage 2	2034-35	2034-35	2034-35	2034-35
Waddamana to Palmerston transfer capacity upgrade	2030-31	2030-31	2030-31	2030-31

A. Part of the Central Queensland to Southern Queensland Expansion project.

B. For QNI proponent timing is different than EISD. AEMO has tested the optimal timing considering the proponent’s timing.

Note: Light teal indicates that a project is delivered at its EISD.

As further detailed in Appendix A5, approximately 6,000 km of transmission is projected to be needed in total by 2050 under the *Step Change* scenario. 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 Victoria.



## A6.4 Step 2: Building candidate development paths

### A6.4.1 Identifying potentially 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 19** 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<sup>24</sup>. 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.

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<sup>24</sup> This does not consider the potentially detrimental impact on social licence, community trust and acceptance.

**Table 19 Potential actionable projects in the Draft 2026 ISP, or 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
<b>Gladstone Project</b>	Actionable in all scenarios	2028-29	4	2032-33
<b>Central Queensland to Southern Queensland Expansion</b>	Found actionable in 2024 ISP	2031-32	4	2035-36
<b>Queensland – New South Wales Interconnector (QNI) Connect</b>	Actionable in <i>Step Change</i> and <i>Accelerated Transition</i>	2033-34	4	2037-38
<b>New England REZ Network Infrastructure Project (REZ option)</b>	Actionable in <i>Step Change</i> and <i>Accelerated Transition</i>	2032-33	4	2036-37
<b>Dubbo Distribution Project</b>	Actionable timing in <i>Accelerated Transition</i> <sup>B</sup>	2030-31 <sup>B</sup>	2 <sup>B</sup>	2032-33 <sup>B</sup>
<b>New England REZ Network Infrastructure Project (Flow path option)</b>	Actionable in <i>Step Change</i> and <i>Accelerated Transition</i>	2032-33	6	2038-39
<b>Sydney Ring North (Hunter Transmission Project 1.0)</b>	Actionable in all scenarios	2029-30	6	2035-36
<b>Sydney Ring South power flow controller option</b>	Actionable in all scenarios	2030-31	4	2034-35
<b>Sydney Ring South – 500 kV option (Stage 1)</b>	Actionable in <i>Accelerated Transition</i>	2033-34	4	2037-38
<b>Sydney Ring South – 500 kV option (Stage 2)</b>	Actionable in <i>Accelerated Transition</i>	2033-34	4	2037-38
<b>Northern Transmission Project</b>	Found actionable in 2024 ISP	2029-30	4	2033-34
<b>Switching Station Near Wondalga</b>	Actionable in <i>Slower Growth</i> and <i>Accelerated Transition</i>	2029-30	2	2031-32
<b>Victoria – New South Wales Interconnector West (VNI West)</b>	Actionable in all scenarios	2031-32	8	2039-40
<b>Western Victoria Reinforcement program</b>	Actionable in all scenarios	2028-29	2	2030-31
<b>Eastern Victoria Reinforcement program</b>	Actionable in <i>Accelerated Transition</i>	2031-32	2	2033-34
<b>Gippsland Offshore Wind Transmission Stage 1</b>	Actionable in all scenarios	2031-32	2	2033-34
<b>Gippsland Offshore Wind Transmission Stage 2 (Phase 1)</b>	Actionable in all scenarios	2033-34	2	2035-36
<b>Gippsland Offshore Wind Transmission Stage 2 (Phase 2)</b>	Actionable in all scenarios	2038-39	2	2040-41
<b>Project Marinus Stage 2</b>	Actionable in all scenarios	2034-35	8	2042-43
<b>Waddamana to Palmerston transfer capacity upgrade</b>	Actionable in all scenarios	2030-31	2	2032-33

A. Humelink, Hunter-Central Coast REZ Network Infrastructure project, and Project Marinus Stage 1 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 the Dubbo Distribution Project is shown alongside transmission options, the ISP framework cannot directly action distribution augmentations. The project may progress through the regulatory investment test for distribution (RIT-D) or the NSW Electricity Infrastructure Investment (EII) Act.

#### A6.4.2 Determining the set of candidate development paths to identify the ODP

A CDP represents a collection of DPs that have similar sets of actionable projects. CDPs vary with respect to these potentially 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 planning horizon).

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 Draft 2026 ISP are shown in **Table 20**, 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 A6.6.

Note that the costs and benefits of CDPs, as well as the CDP collection itself, for this Draft 2026 ISP are not directly comparable to the CDPs used in the 2024 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 are based on the least-cost DPs from each scenario:

- **CDP1** which is based on the least-cost DP in *Slower Growth* scenario as defined in **Table 18**,
- **CDP2** which is based on the least-cost DP in *Step Change* scenario as defined in **Table 18**, and
- **CDP3** which is based on the least-cost DP in *Accelerated Transition* scenario as defined in **Table 18**.

CDP2 forms the basis of **CDP4**, but **CDP4** includes an actionable Switching Station Near Wondalga as it was found to be optimal at its EISD in both CDP1 and CDP3.

The following CDPs, which are variations of CDP4, assess 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:

- **CDP5** features delivery of Sydney Ring South – 500 kV option (Stage 1) within its actionable window in contrast with CDP4, given the augmentation's delivery is found optimal within its actionable window in CDP1.
- **CDP6** extends CDP5 to features delivery of the 500 kV option (Stage 2) to Sydney Ring South at actionable timing, given the augmentation's delivery is found optimal within its actionable window in CDP1.
- **CDP7** features delivery of Dubbo Distribution Project within its actionable window in contrast with CDP4, given the augmentation's delivery is found optimal within its actionable window in CDP1.
- **CDP8** features delivery of Central Queensland to Southern Queensland Expansion within its actionable window in contrast with CDP4, given it was found to be an actionable project in the 2024 ISP.
- **CDP9** features delivery of the smaller Eastern Victoria Reinforcement program (Option 1) within its actionable window in contrast with CDP4, given the augmentation's delivery is found optimal within its actionable window in CDP1.

- **CDP10** features delivery of the larger Eastern Victoria Reinforcement program (Option 2) to within its actionable window instead of the smaller option in contrast with CDP9 to ensure robustness of the assessment for of this flow path<sup>25</sup>.
- **CDP11** features delivery of the Northern Transmission Project (Mid North South Australia REZ project) at a timing within its actionable window, given it was found to be an actionable project in the 2024 ISP.

To assess the impact of delivery of potential actionable projects after their actionable window, these CDPs were created:

- **CDP12** features delivery of both Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South power flow controller option outside their actionable windows in contrast with CDP4.
- **CDP13** features delivery of only Sydney Ring South power flow controller option outside its actionable window in contrast with CDP4.
- **CDP14** features delivery of Gladstone Project outside its actionable window in contrast with CDP4.
- **CDP15** features delivery of Western Victoria Reinforcement program outside its actionable window in contrast with CDP4.
- **CDP16** features delivery of both New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect outside their actionable windows in contrast with CDP4.
- **CDP17** features delivery of Queensland – New South Wales Interconnector (QNI) Connect outside its actionable window in contrast with CDP4.
- **CDP18** features delivery of Gippsland Offshore Wind Transmission Stage 2 (Phase 2) outside its actionable window in contrast with CDP4.
- **CDP19** features delivery of both Gippsland Offshore Wind Transmission Stage 1 and Gippsland offshore wind transmission stage 2 (Phase 1) outside their actionable windows in contrast with CDP4.
- **CDP20** features delivery of Waddamana to Palmerston transfer capacity upgrade outside its actionable window in contrast with CDP4.
- **CDP21** features delivery of Project Marinus Stage 2 outside its actionable window in contrast with CDP4.
- **CDP22** features delivery of Victoria – New South Wales Interconnector West (VNI West) outside its actionable window in contrast with CDP4.
- **CDP23** features delivery of all actionable projects in CDP4 to a timing outside their actionable window.

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<sup>25</sup> The least-cost development path analyses revealed very little difference in relative total system cost outcomes between these two options.

Table 20 Candidate development paths summary

In these CDPs...		...these projects would be actionable																					
CDP	Description	Gladstone Project	Central Queensland to Southern Queensland Expansion	Queensland – New South Wales Interconnector (QNI) Connect	New England REZ Network Infrastructure Project (REZ)	New England REZ Network Infrastructure Project (Flow path)	Dubbo Distribution Project <sup>c</sup>	Sydney Ring North (Hunter Transmission Project 1.0)	Sydney Ring South power flow controller option	Sydney Ring South – 500 kV option (Stage 1)	Sydney Ring South – 500 kV option (Stage 2)	Northern Transmission Project	Switching Station Near Wondalga	Victoria – New South Wales Interconnector West (VNI West)	Western Victoria Reinforcement program	Eastern Victoria Grid Reinforcement (Option 1)	Eastern Victoria Grid 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)	Project Marinus Stage 2	Waddamana to Palmerston transfer capacity upgrade	
CDP1	Least-cost DP for Slower Growth	✓												✓	✓	✓			✓	✓	✓	✓	✓
CDP2	Least-cost DP for Step Change	✓		✓	✓	✓		✓	✓						✓	✓			✓	✓	✓	✓	✓
CDP3	Least-cost DP for Accelerated Transition	✓		✓	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓		✓	✓	✓	✓	✓
CDP4	CDP2 with actionable Switching Station Near Wondalga	✓		✓	✓	✓		✓	✓					✓	✓	✓			✓	✓	✓	✓	✓
CDP5	CDP4 with actionable Sydney Ring South – 500 kV option (Stage 1)	✓		✓	✓	✓		✓	✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP6	CDP4 with actionable Sydney Ring South – 500 kV option (Stage 2)	✓		✓	✓	✓		✓	✓	✓	✓			✓	✓	✓			✓	✓	✓	✓	✓
CDP7	CDP4 with actionable Dubbo Distribution Project	✓		✓	✓	✓	✓	✓	✓					✓	✓	✓			✓	✓	✓	✓	✓
CDP8	CDP4 with actionable Central Queensland to Southern Queensland Expansion	✓	✓	✓	✓	✓		✓	✓					✓	✓	✓			✓	✓	✓	✓	✓
CDP9	CDP4 with actionable Eastern Victoria Grid Reinforcement (Option 1)	✓		✓	✓	✓		✓	✓					✓	✓	✓	✓		✓	✓	✓	✓	✓
CDP10	CDP4 with actionable Eastern Victoria Grid Reinforcement (Option 2)	✓		✓	✓	✓		✓	✓					✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
CDP11	CDP4 with actionable Northern Transmission Project	✓		✓	✓	✓		✓	✓			✓		✓	✓	✓			✓	✓	✓	✓	✓
CDP12	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	✓		✓	✓	✓		✗	✗					✓	✓	✓			✓	✓	✓	✓	✓

Step 2: Building candidate development paths

In these CDPs...		...these projects would be actionable																					
CDP	Description	Gladstone Project	Central Queensland to Southern Queensland Expansion	Queensland – New South Wales Interconnector (QNI) Connect	New England REZ Network Infrastructure Project (REZ)	New England REZ Network Infrastructure Project (Flow path)	Dubbo Distribution Project <sup>c</sup>	Sydney Ring North (Hunter Transmission Project 1.0)	Sydney Ring South power flow controller option	Sydney Ring South – 500 kV option (Stage 1)	Sydney Ring South – 500 kV option (Stage 2)	Northern Transmission Project	Switching Station Near Wondalga	Victoria – New South Wales Interconnector West (VNI West)	Western Victoria Reinforcement program	Eastern Victoria Grid Reinforcement (Option 1)	Eastern Victoria Grid 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)	Project Marinus Stage 2	Waddamana to Palmerston transfer capacity upgrade	
CDP13	CDP4 without actionable Sydney Ring South power flow controller option	✓	✓	✓	✓	✓	✓	✓	✗				✓	✓	✓				✓	✓	✓	✓	✓
CDP14	CDP4 without actionable Gladstone Project	✗	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓				✓	✓	✓	✓	✓
CDP15	CDP4 without actionable Western Victoria Reinforcement program	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✗				✓	✓	✓	✓	✓
CDP16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	✓	✗	✗	✗	✓	✓	✓	✓				✓	✓	✓				✓	✓	✓	✓	✓
CDP17	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	✓	✗	✓	✓	✓	✓	✓	✓				✓	✓	✓				✓	✓	✓	✓	✓
CDP18	CDP4 without actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓				✓	✓	✗	✓	✓
CDP19	CDP4 without actionable Gippsland Offshore Wind Transmission Stage 1 and Stage 2 (Phase 1)	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓				✗	✗	✓	✓	✓
CDP20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓				✓	✓	✓	✓	✗
CDP21	CDP4 without actionable Project Marinus Stage 2	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓				✓	✓	✓	✗	✓
CDP22	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	✓	✓	✓	✓	✓	✓	✓	✓				✓	✗	✓				✓	✓	✓	✓	✓
CDP23	CDP4 with no non-anticipated actionable projects	✗	✗	✗	✗	✗	✗	✗	✗				✗	✗	✗				✗	✗	✗	✗	✗

A: ✓ refers to a project added as actionable to CDP4, ✗ refers to a project being removed as actionable from CDP4.

B: Teal rows represent least cost DPs. Purple rows represent CDP4 and the CDPs developed from it.

C: The ISP framework does not apply to this project, however, this could go through the normal Regulatory Investment Test for Distribution.



## A6.5 Steps 3 and 4: Assessing the candidate development paths

### A6.5.1 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 A6.8). 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 21** 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 21 Performance of candidate development paths across scenarios (in \$ billion) – ranked in order of weighted net market benefits**

CDP	Description	Scenario-specific net market benefits			Approach A		Approach B	
		Slower Growth	Step Change	Accelerated Transition	Weighted net market benefits (WNMB)	Rank based on WNMB	Worst weighted regrets (WWR)	Rank based on WWR
CDP4	CDP2 with actionable Switching Station Near Wondalga	12.64	25.48	33.57	24.20	1	0.42	5
CDP6	CDP4 with actionable Sydney Ring South – 500 kV option (Stage 2)	12.42	25.35	33.94	24.18	2	0.48	12
CDP16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	14.18	24.95	32.84	24.17	3	0.40	2
CDP10	CDP4 with actionable Eastern Victoria Grid Reinforcement (Option 2)	12.57	25.46	33.55	24.16	4	0.44	8
CDP2	Least-cost DP for Step Change	12.64	25.48	33.43	24.16	5	0.42	3
CDP20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	12.64	25.42	33.37	24.12	6	0.42	4
CDP9	CDP4 with actionable Eastern Victoria Grid Reinforcement (Option 1)	12.45	25.42	33.55	24.11	7	0.47	10
CDP8	CDP4 with actionable Central Queensland to Southern Queensland Expansion	12.48	25.25	33.76	24.10	8	0.46	9
CDP7	CDP4 with actionable Dubbo Distribution Project	12.42	25.45	33.45	24.09	9	0.48	13
CDP15	CDP4 without actionable Western Victoria Reinforcement program	12.63	25.36	33.30	24.07	10	0.42	6
CDP13	CDP4 without actionable Sydney Ring South power flow controller option	12.58	25.41	33.20	24.05	11	0.44	7
CDP11	CDP4 with actionable Northern Transmission Project	12.38	25.31	33.25	23.96	12	0.49	14
CDP3	Least-cost DP for Accelerated Transition	12.09	24.84	34.31	23.96	13	0.57	15
CDP17	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	13.14	24.81	33.27	23.94	14	0.31	1
CDP18	CDP4 without actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	12.43	25.09	33.15	23.85	15	0.48	11

		Scenario-specific net market benefits			Approach A		Approach B	
<b>CDP21</b>	CDP4 without actionable Project Marinus Stage 2	11.33	25.38	33.08	23.67	16	0.78	18
<b>CDP22</b>	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	11.73	25.28	31.97	23.43	17	0.67	16
<b>CDP14</b>	CDP4 without actionable Gladstone Project	12.40	24.81	31.57	23.28	18	0.74	17
<b>CDP5</b>	CDP4 with actionable Sydney Ring South – 500 kV option (Stage 1)	9.97	24.93	32.22	22.86	19	1.14	20
<b>CDP19</b>	CDP4 without actionable Gippsland Offshore Wind Transmission Stage 1 and Stage 2 (Phase 1)	12.28	24.17	30.51	22.67	20	1.03	19
<b>CDP12</b>	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	12.33	24.34	29.12	22.39	21	1.40	21
<b>CDP1</b>	Least-cost DP for Slower Growth	14.20	22.53	28.54	21.91	22	1.56	22
<b>CDP23</b>	CDP4 with no non-anticipated actionable projects	11.61	21.54	20.77	18.65	23	3.66	23

The table above highlights that nearly half of CDPs deliver over \$25 billion of NPV of net market benefits in the most-likely scenario and over \$24 billion when weighted across the three scenarios.

The results shows that there are significant benefits in commencing, or continuing, with the potentially actionable transmission developments. In contrast, delaying all projects to outside of their actionable window (CDP23) is a key outlier, delivering \$5.5 billion less benefits than the top CDP, and having over \$3.3 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 clearly less beneficial than continuing to develop the NEM’s transmission system with urgency.

### A6.5.2 Newly committed and anticipated projects since the 2024 ISP

Since the 2024 ISP, three 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.

#### HumeLink

The transmission network between Southern New South Wales (SNSW) and Central New South Wales (CNSW) sub-regions provides access for the hydroelectric 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 December 2025 publication of the Transmission Augmentation Information page<sup>26</sup>, it is now sufficiently progressed to be considered an anticipated project, therefore it was included across all scenarios and CDPs, and it has not been further assessed in this ISP.

## Project Marinus Stage 1

Marinus Link 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 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 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<sup>27</sup>.

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 the ISP.

### A6.5.3 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.

For each of the projects discussed further 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 projects except the project of interest. This comparison is provided on the *Step Change* scenario, and is referred to as the 'TOOT' (Take-one-out-at-a-time) approach. For the purposes of this Draft 2026 ISP, this has been assessed using CDP4 (the CDP with highest weighted net market benefits).

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<sup>28</sup>. This is completed by comparing the net market benefits and weighted regrets of a CDP where the delivery of the project of interest is delayed until after 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 comparisons in the following subsections are against CDP4.

<sup>26</sup> At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

<sup>27</sup> At <https://www.aemo.com.au/newsroom/news-updates/project-marinus-passes-feedback-loop-assessment>.

<sup>28</sup> This Draft 2026 ISP has not found any project that would benefit from potential staging, either in relation to early works to maintain option value for future progression within the actionable window, or deferral if it is later determined after completing early works.

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 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.

## Gladstone Project

<b>EISD</b>	March 2029
<b>Actionable window length</b>	4 years (actionable in 2024 ISP)
<b>Cost</b>	\$2,442 million ( <i>Slower Growth, 2028-29</i> ) \$2,442 million ( <i>Step Change, 2028-29</i> ) \$2,480 million ( <i>Accelerated Transition, 2028-29</i> )
<b>Flow path or REZ</b>	CQ-GG
<b>Capacity increase</b>	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 actionable in the 2024 ISP and thus 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 all three scenarios to provide reliability of supply to the sub-region after this closure.

Assessing the relative market benefits of Gladstone Project and Queensland SuperGrid South via TOOT analysis

Gladstone Project is a pre-requisite for the development of Queensland SuperGrid South<sup>29</sup>. As such, if the project is not included in a CDP, then the dependent project, in this case Queensland SuperGrid South, is also taken out. **Table 22** presents the relative market benefits associated with both projects being delivered at their EISDs (Gladstone Project in 2028-29 and Queensland SuperGrid South in 2035-36). The two projects deliver around \$7.4 billion in net market benefits which mainly comes from avoided fuel costs, followed by generator and storage capital deferral. The projects avoid the need to build increasing amounts of flexible gas capacity (and pay for associated gas consumption) in Gladstone Grid from the mid-2030s onwards. By 2050, nearly 2.9 GW of flexible gas capacity is avoided in the Gladstone Grid sub-region.

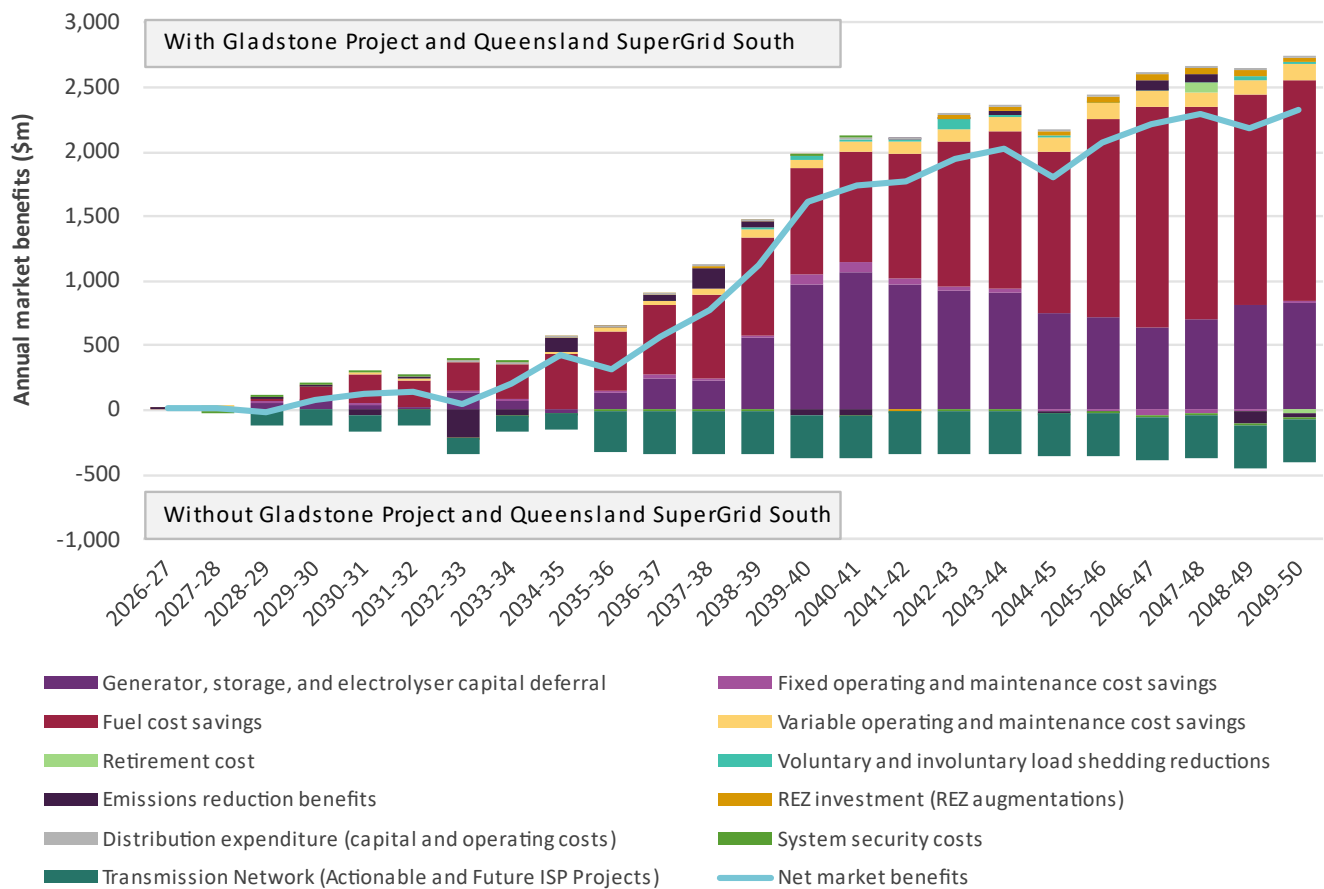
**Table 22 Relative market benefits of Gladstone Project and Queensland SuperGrid South, Step Change**

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	3,248
Fixed operating and maintenance cost savings	143
Fuel cost savings	5,537
Variable operating and maintenance cost savings	413
Retirement cost	9
Voluntary and involuntary load shedding reductions	71
Emissions reduction benefits	4

<sup>29</sup> Queensland SuperGrid South is the second part of the Central Queensland to Southern Queensland Expansion.

Class of market benefit	Relative market benefit (NPV, \$ million)
REZ investment (REZ augmentations)	77
Distribution expenditure (capital and operating costs)	31
System security costs	-37
<b>Gross market benefits</b>	<b>9,495</b>
Transmission Network (Actionable and Future ISP Projects)	-2,062
<b>Total net market benefits</b>	<b>7,434</b>

**Figure 18 Annual relative market benefits of Gladstone Project and Queensland SuperGrid South in Step Change (2033-34)**



### 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 CDP4, in which the project’s delivery is within the actionable window, and CDP14, in which the project’s delivery is outside its actionable window. In both cases, Queensland SuperGrid South is delivered as a future project, meaning the project’s delay does not inhibit the subsequent project. **Table 23** shows that Gladstone Project would deliver an additional \$912 million in weighted net market benefits when actionable, reducing the otherwise high costs associated with reliability difficulties if the project was delayed.

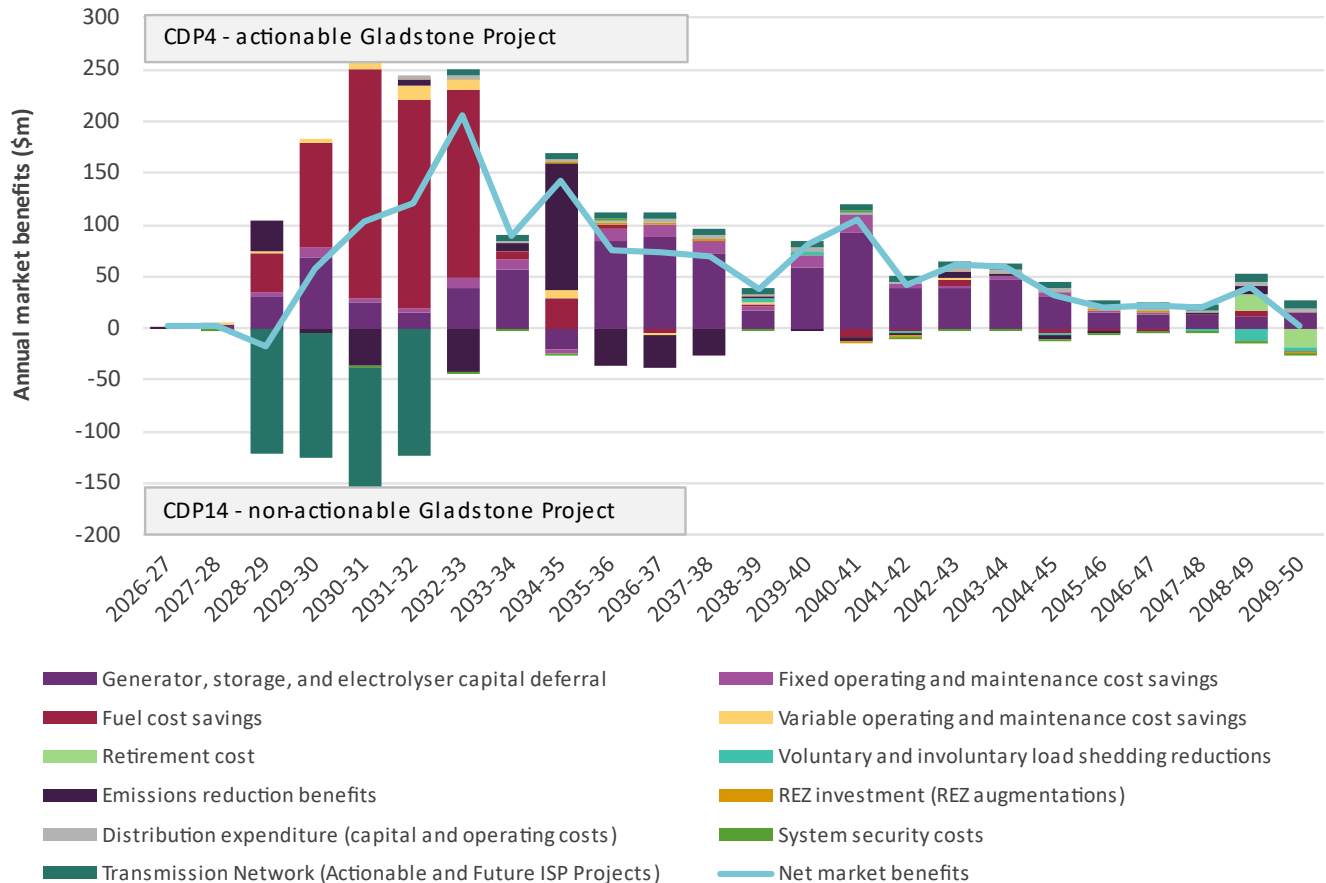
**Table 23 Comparing net market benefits between CDP4 and CDP14 (\$ billion) – Gladstone Project**

	CDP4 – with actionable Gladstone Project	CDP14 – without actionable Gladstone Project	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.40	-0.24
<i>Step Change</i>	25.48	24.81	-0.67
<i>Accelerated Transition</i>	33.57	31.57	-2.00
<b>Weighted net market benefits</b>	<b>24.20</b>	<b>23.28</b>	<b>-0.91</b>
<b>Ranking based on weighted net market benefits</b>	<b>1</b>	<b>18</b>	<b>N/A</b>

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 utility-scale storage, 450 MW of flexible gas, and 200 MW of utility-scale solar by 2030-31 in Gladstone Grid, leading to major savings in generator and storage capital expenditure, fixed operating and maintenance costs, and fuel costs associated with the subsequent increase in flexible gas. Similar sources of benefits are observed in *Accelerated Transition*. Benefits are less pronounced in *Slower Growth* owing to assumed industrial load closures in Gladstone Grid from 2029-30 onwards in this scenario. Nonetheless, Gladstone Project is still shown to deliver benefits in *Slower Growth* to reinforce supply.

**Figure 19 Net market benefits of an actionable Gladstone Project, Step Change**



Assessing the regrets associated with Gladstone Project as an actionable project

**Table 24** 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 to \$317 million. The weighted regret cost is highest in *Accelerated Transition* as the project supports the higher demand in that scenario.

**Table 24 Weighted and worst weighted regrets of CDP4 and CDP14 (\$ million) – Gladstone Project**

	CDP4 – with actionable Gladstone Project	CDP14 – without actionable Gladstone Project	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	487	64
<i>Step Change</i>	2	310	308
<i>Accelerated Transition</i>	200	741	541
<b>Worst weighted regrets</b>	423	741	317
<b>Ranking based on worst weighted regrets</b>	5	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.

## New England REZ Network Infrastructure Project

	REZ augmentation	Flow path augmentation
<b>EISD</b>	July 2032	July 2032
<b>Actionable window length</b>	4 years (actionable in 2024 ISP)	6 years (actionable in 2024 ISP)
<b>Cost</b>	\$1,182 million ( <i>Slower Growth</i> , 2032-33) \$1,191 million ( <i>Step Change</i> , 2032-33) \$1,230 million ( <i>Accelerated Transition</i> , 2032-33)	\$2,777 million ( <i>Slower Growth</i> , 2032-33) \$2,798 million ( <i>Step Change</i> , 2032-33) \$2,880 million ( <i>Accelerated Transition</i> , 2032-33)
<b>Flow path or REZ</b>	New England REZ	CNSW-NNSW
<b>Capacity increase</b>	2,400 MW forward / N/A MW reverse	2,400 MW forward / 2,400 MW reverse

The New England REZ Network Infrastructure Project is comprised of a REZ and a flow path augmentation. The augmentation has an EISD of 2031-32 and a four-year actionable window, given it was found to be an actionable project in the 2024 ISP. The augmentation of the REZ provides an increase of 2,400 MW transfer capacity from the New England REZ while the flow path augmentation is a proposed 500 kV line that provides 2,400 MW of additional transfer capacity between Central New South Wales and North New South Wales sub-regions. These projects are a pre-requisite to the delivery of QNI Connect.

This section presents two assessments – first is an assessment of New England REZ Network Infrastructure Project if QNI Connect is delivered as a future project, and in the second, QNI Connect is an actionable project.

The TOOT analysis presented below requires neither project to be delivered at any time in the outlook period.

Further to the New England augmentations discussed in this section, the latest 2025 Infrastructure Investment Objectives Report includes a subsequent augmentation to New England in the 20-year development pathway that best met New South Wales’ legislated objectives for energy infrastructure. In December 2021 the New England REZ was formally declared to progress under the *Electricity Infrastructure Act 2020* (NSW) rather than through the RIT-T framework. This declaration

identifies that EnergyCo is the appointed infrastructure planner responsible for coordinating the delivery of the REZ. Ongoing analysis and stakeholder engagement between now and June 2026 is needed to ascertain whether the subsequent stage will optimise benefits to consumers in the 2026 ISP. However, all aspects of this transmission project are expected to progress under the *Electricity Infrastructure Investment Act 2020* (NSW).

### Assessing the relative market benefits of New England REZ Network Infrastructure Project and QNI Connect via TOOT analysis

**Table 25** presents the benefits that New England REZ Network Infrastructure Project and QNI Connect provide in *Step Change*<sup>30</sup>. Overall, these augmentations provide relative market benefits of \$1.68 billion which mostly come from avoided generator and storage capital deferral followed by fixed operating and maintenance cost savings.

If both New England REZ Network Infrastructure Project and QNI Connect are developed, a smaller and less-costly build of wind capacity in Northern New South Wales is unlocked, rather than developing over 3 GW of mostly utility-scale solar in Central New South Wales by 2049-50, as shown in **Figure 20**.

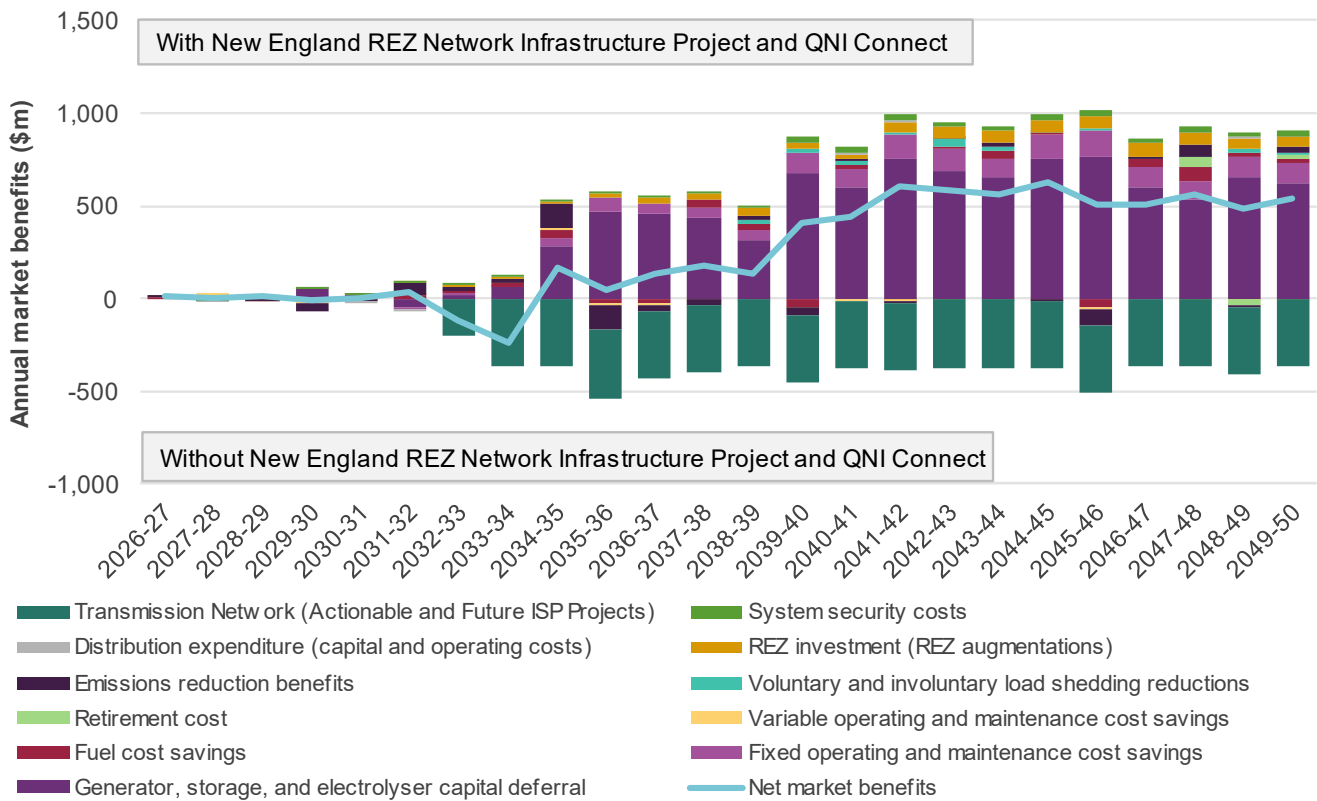
The development of both these projects, and in particular QNI Connect which depends on this project (see Section A6.5.5), also reduces the need for over 2.3 GW of utility-scale storage from 2039-40 across the NEM with improved access to the firming capacity from Borumba Pumped Hydro and Queensland black coal.

**Table 25** Relative market benefits of New England REZ Network Infrastructure Project and QNI Connect in *Step Change*

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	2,880
Fixed operating and maintenance cost savings	477
Fuel cost savings	89
Variable operating and maintenance cost savings	-19
Retirement cost	7
Voluntary and involuntary load shedding reductions	51
Emissions reduction benefits	0
REZ investment (REZ augmentations)	236
Distribution expenditure (capital and operating costs)	9
System security costs	130
<b>Gross market benefits</b>	<b>3,859</b>
Transmission Network (Actionable and Future ISP Projects)	-2,188
<b>Total net market benefits</b>	<b>1,671</b>

<sup>30</sup> Due to the pre-requisite delivery requirements, TOOT analysis of the New England REZ Transmission Link also requires removal of QNI Connect.

**Figure 20 Comparison of relative market benefits with and without New England REZ Network Infrastructure Project and QNI Connect in Step Change (at 2032-33)**



Assessing the net market benefits of New England REZ Network Infrastructure Project as an actionable project (with QNI fixed as a non-actionable project)

To isolate the impact of New England REZ Network Infrastructure Project, QNI Connect is kept as a non-actionable project in both CDPs. **Table 26** provides an assessment of the change in net market benefits associated with delaying New England REZ Network Infrastructure Project.

Delivery of the project beyond its actionable window increases weighted net market benefits by around \$231 million which mostly comes from deferring the augmentation in *Slower Growth*<sup>31</sup> and to 2038-39 in *Step Change*, which amounts to \$1,038 million and \$146 million, respectively. However, if the project is delivered at its EISD in the *Accelerated Transition* scenario, it would provide around \$432 million of relative market benefits from deferral of generator and storage capital costs.

<sup>31</sup> The project is not identified as needed in the ISP forecast horizon in the *Slower Growth* scenario.

**Table 26 Comparing net market benefits between CDP17 and CDP16 (\$ billion) – New England REZ Network Infrastructure Project (with QNI Connect fixed as a non-actionable project)**

	CDP17 – with actionable New England REZ Network Infrastructure Project (QNI Connect non-actionable)	CDP16 – without actionable New England REZ Network Infrastructure Project (QNI Connect non-actionable)	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	13.14	14.18	1.04
<i>Step Change</i>	24.81	24.95	0.15
<i>Accelerated Transition</i>	33.27	32.84	-0.43
<b>Weighted net market benefits</b>	23.94	24.17	0.23
<b>Ranking weighted net market benefits</b>	14	3	N/A

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*, delivery of this project allows for increased development in Northern New South Wales sub-region which take advantage of the augmentation, with around 1.5 GW of additional wind capacity and 800 MW of utility-scale solar developed by 2034-35. The project also defers capacity in New South Wales – around 1.7 GW of utility-scale solar from 2032-33 in Central New South Wales and South New South Wales sub-regions and up to 1.7 GW of wind capacity in Central New South Wales by 2036-37. In *Slower Growth*, given both projects’ optimal timing is beyond 2049-50, the project results in very limited savings and very small amounts of deferred capacity over the modelling horizon. These benefits do not outweigh the additional cost of delivering this project at the EISD in these scenarios.

In *Accelerated Transition*, the projects avoid generation and storage capital expenditure by avoiding nearly 1 GW of utility-scale storage to be developed across the NEM, nearly 2 GW of utility-scale solar capacity in New South Wales, and around 1.7 GW of wind capacity in Central New South Wales. In this scenario, these benefits outweigh the additional cost of delivering this project at its EISD.

As this project is being progressed through the *Electricity Infrastructure Act 2020 (NSW)*, which will be informed by the modelling that is not required to use the same scenarios, or their inputs and assumptions, as the ISP. The ISP outcomes associated with *Slower Growth* may therefore not have significant influence on the investment decision for this project.

Assessing the regrets associated with New England REZ Network Infrastructure Project (with QNI fixed as a non-actionable project)

**Table 27** presents the weighted and worst weighted regrets associated with delaying New England REZ Network Infrastructure Project. The largest source of regret in CDP16 (where the project is delivered at a non-actionable timing) comes from *Accelerated Transition*, where the weighted regret is estimated to be \$117 million. This highlights the importance of this project in scenarios with higher assumed load growth.

**Table 27 Weighted and worst weighted regret of CDP17 and CDP16 (\$ million) – New England REZ Network Infrastructure Project**

	CDP17 – with actionable New England REZ Network Infrastructure Project (QNI Connect non-actionable)	CDP16 – without actionable New England REZ Network Infrastructure Project (QNI Connect non-actionable)	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	288	8	-280
<i>Step Change</i>	311	244	-67
<i>Accelerated Transition</i>	280	397	117
<b>Worst weighted regrets</b>	311	397	86
<b>Ranking based on worst weighted regrets</b>	1	2	N/A

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 New England REZ Network Infrastructure Project and QNI Connect as actionable projects

The discussions in the previous sections are based on a premise that QNI Connect is delivered at a non-actionable timing, however, the next two sub-sections are focused on the benefits and regrets of delivering both New England REZ Network Infrastructure Project and QNI Connect at actionable timing.

**Table 28** shows that delivering both QNI Connect and its prerequisite – New England REZ Network Infrastructure Project – at actionable timings as featured in CDP4 has positive net market benefits in *Step Change* and *Accelerated Transition* of around \$525 million and \$728 million respectively, but it has negative net market benefits of \$1.54 billion in *Slower Growth* compared with CDP 16 which delays both projects to a non-actionable timing. On a weighted basis, delivering both projects at their actionable timing results in positive net market benefits of \$22 million.

**Table 28 Comparing net market benefits between CDP4 and CDP16 (\$ billion) – New England REZ Network Infrastructure Project and QNI Connect**

	CDP4 – with actionable New England REZ Network Infrastructure Project and QNI Connect	CDP16 – without actionable New England REZ Network Infrastructure Project and QNI Connect	Change in net market benefits associated with non-actionable delivery of the projects <sup>A</sup>
<i>Slower Growth</i>	12.64	14.18	1.54
<i>Step Change</i>	25.48	24.95	-0.52
<i>Accelerated Transition</i>	33.57	32.84	-0.73
<b>Weighted net market benefits</b>	24.20	24.17	-0.02
<b>Ranking weighted net market benefits</b>	1	3	N/A

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 *Slower Growth*, the project delivers gross benefits by delaying the need for around 800 MW of additional wind capacity in Queensland from 2034-35 and flexible gas capacity in Queensland and New South Wales. Development of the project at an actionable timing also avoids fuel and emission costs during the 2040s, but these avoided costs are not sufficient to offset the cost of the projects.

In *Step Change* and *Accelerated Transition*, the benefits of the projects are similar with those discussed above – deferring significant utility-scale solar capacity in New South Wales and wind capacity in Queensland in favour of developing wind

capacity in the New England REZ. As discussed in the case of QNI Connect in isolation in Section A6.5.5, significant benefits are also derived by avoiding the need to develop additional firm capacities in Victoria.

Assessing the regrets associated with New England REZ Network Infrastructure Project and QNI Connect as actionable projects

As seen in **Table 29**, delaying the delivery of these projects beyond their actionable windows will incur higher regret coming from the *Step Change* and *Accelerated Transition* scenarios, where the risk associated with under-investment increases to around \$241 million resulting from lost opportunity that these projects provide to avoid additional firming capacity and other builds in that scenario.

**Table 29 Weighted and worst weighted regret of CDP4 and CDP16 (\$ million) – New England REZ Network Infrastructure Project and QNI Connect**

	CDP4 – with actionable New England REZ Network Infrastructure Project and QNI Connect	CDP16 – without actionable New England REZ Network Infrastructure Project and QNI Connect	Change in weighted regrets associated with non-actionable delivery of the projects <sup>A</sup>
<i>Slower Growth</i>	423	8	-416
<i>Step Change</i>	2	244	241
<i>Accelerated Transition</i>	200	397	196
<b>Worst weighted regrets</b>	423	397	-27
<b>Ranking based on worst weighted regrets</b>	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.

### Sydney Ring North (Hunter Transmission Project 1.0)

<b>EISD</b>	November 2029
<b>Actionable window length</b>	6 years (actionable in 2022 and 2024 ISPs)
<b>Cost</b>	\$1,429 million ( <i>Slower Growth</i> , 2029-30) \$1,436 million ( <i>Step Change</i> , 2029-30) \$1,457 million ( <i>Accelerated Transition</i> , 2029-30)
<b>Flow path or REZ</b>	CNSW-SNW North
<b>Capacity increase</b>	5,000 MW forward

Sydney Ring North (Hunter Transmission Project 1.0) provides a 5,000 MW upgrade to the northern side of the Central New South Wales to Sydney, Newcastle and Wollongong flow path. 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.

The optimal timing of Sydney Ring North (Hunter Transmission Project 1.0) is at its EISD of November 2029 across all scenarios (that is, rather than delaying to beyond actionable window), as it prepares the New South Wales power system to enable additional transfer capacity to support reliability for the Sydney, Newcastle and Wollongong load centres when coal capacity retires.

Assessing the relative market benefits of Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South via TOOT analysis

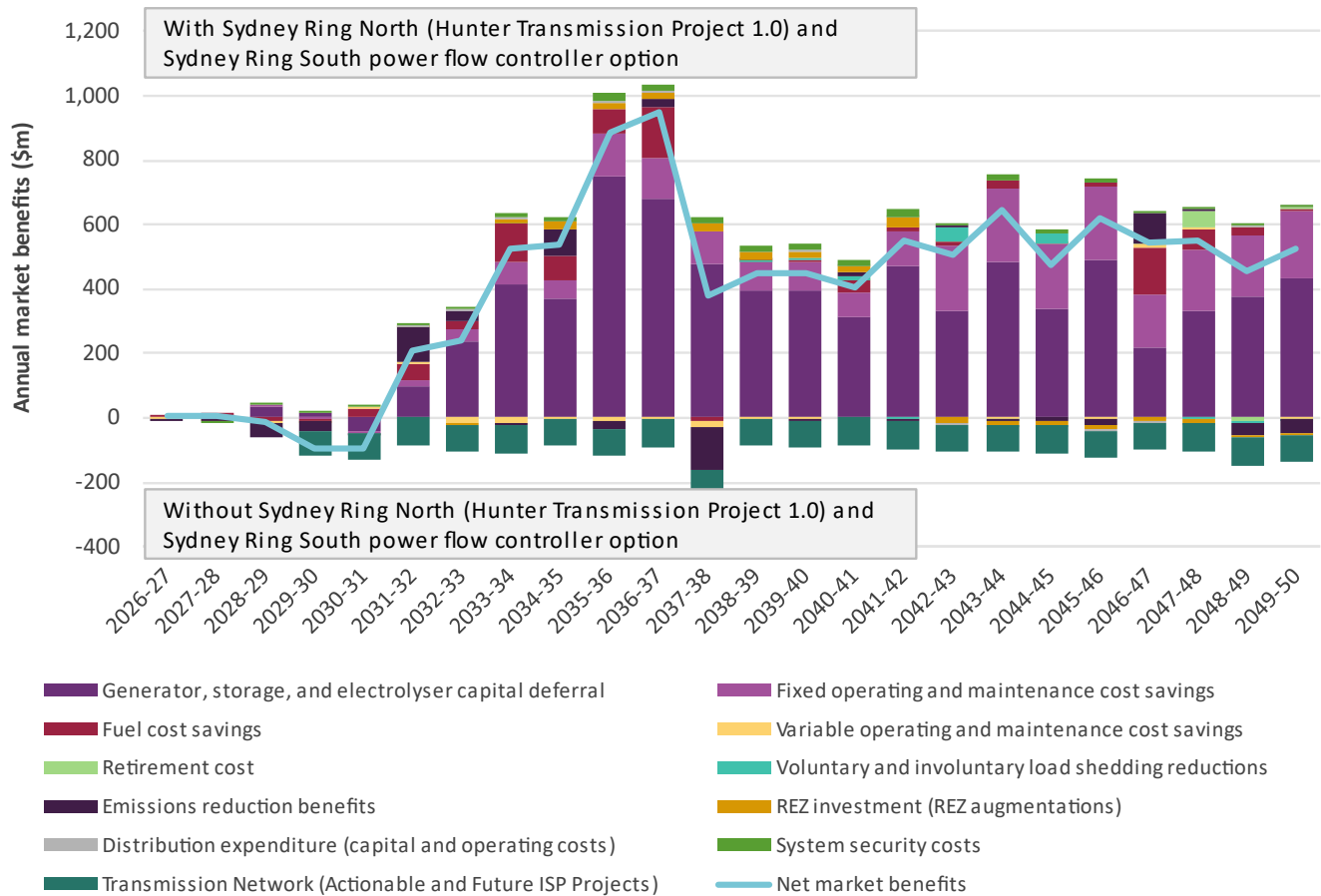
Sydney Ring North (Hunter Transmission Project 1.0) is a pre-requisite of another flow path augmentation option (Sydney Ring South power flow controller option); hence delivery of both projects must be excluded when undertaking TOOT analysis. **Table 30** and **Figure 21** present the relative market benefits of these two projects in *Step Change*.

Overall, the projects contribute around \$3.4 billion to the ODP’s net market benefits in *Step Change*, particularly from 2031-32 to reduce generation and storage capital costs, and subsequent savings for operating and maintenance costs.

**Table 30** Relative market benefits of Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South power flow controller option in *Step Change*

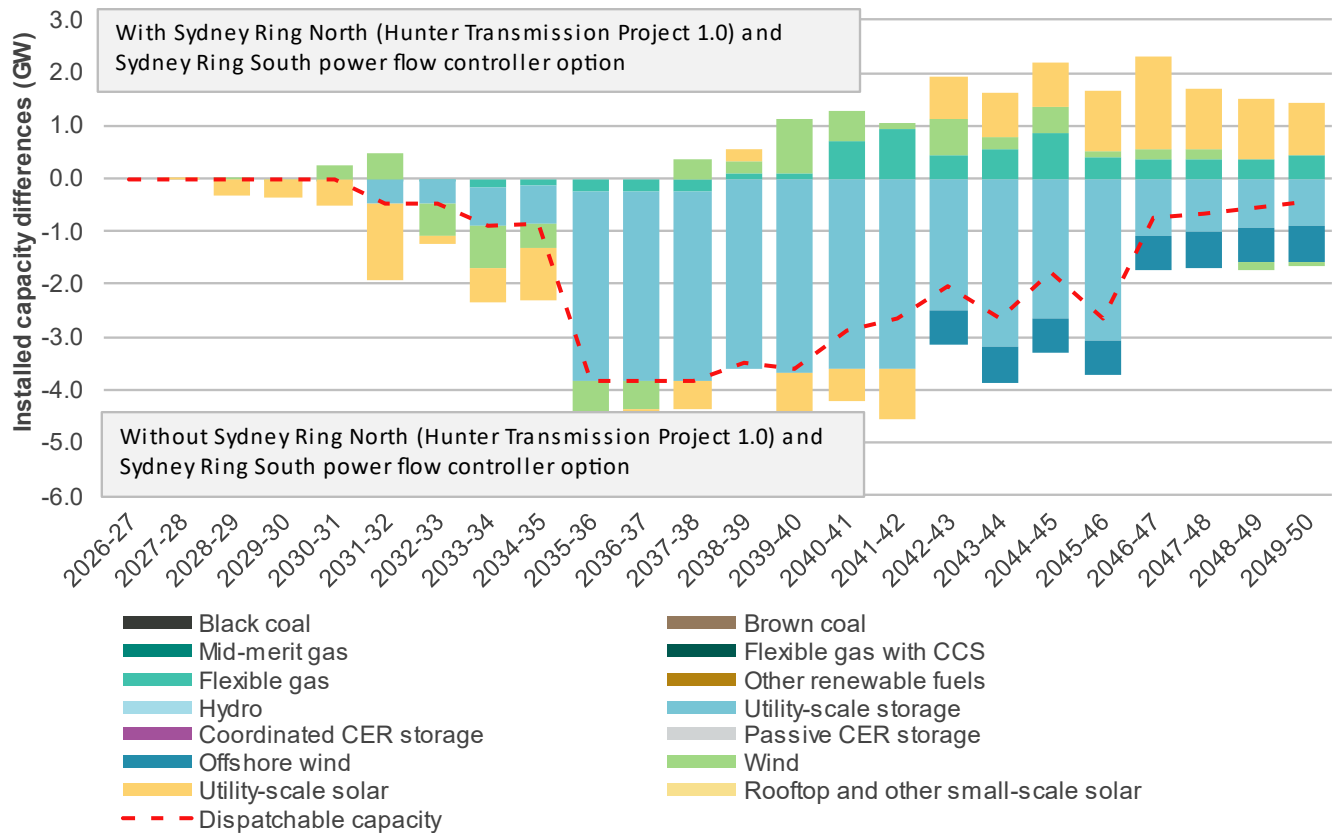
Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	2,739
Fixed operating and maintenance cost savings	777
Fuel cost savings	362
Variable operating and maintenance cost savings	-31
Retirement cost	10
Voluntary and involuntary load shedding reductions	30
Emissions reduction benefits	2
REZ investment (REZ augmentations)	59
Distribution expenditure (capital and operating costs)	14
System security costs	97
<b>Gross market benefits</b>	<b>4,059</b>
Transmission Network (Actionable and Future ISP Projects)	-689
<b>Total net market benefits</b>	<b>3,370</b>

**Figure 21 Annual relative market benefits of Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South power flow controller option in Step Change (2029-30 and 2030-31, respectively)**



As shown in **Figure 22**, delivery of the two projects at actionable timings compared to not at all avoids around 3.6 GW of utility-scale storage in the 2030s – of which, 2.1 GW would be located in Sydney, Newcastle and Wollongong and 1.2 GW in South New South Wales. Without the projects, additional utility-scale solar resources would be required in the SNW sub-region over the period to the late 2030s and offshore wind from 2042-43. By delivering the projects, lower cost utility-scale solar, wind, and flexible gas in Central New South Wales, Northern New South Wales, and Queensland can be developed and operated from the 2040s instead.

**Figure 22 Comparison of capacity with and without Sydney Ring North (Hunter Transmission Project 1.0) and Sydney Ring South power flow controller option in Step Change (2029-30 and 2030-31, respectively)**



Assessing the net market benefits of Sydney Ring North (Hunter Transmission Project 1.0) as an actionable project

The benefits of Sydney Ring North (Hunter Transmission Project 1.0) as an actionable project can be assessed by comparing CDP13, which delivers the project at an actionable timing, against CDP12, which delays its delivery beyond its actionable window. In both CDPs, Sydney Ring South power flow controller option is delayed after its actionable window to insulate the benefits of Sydney Ring North (Hunter Transmission Project 1.0).

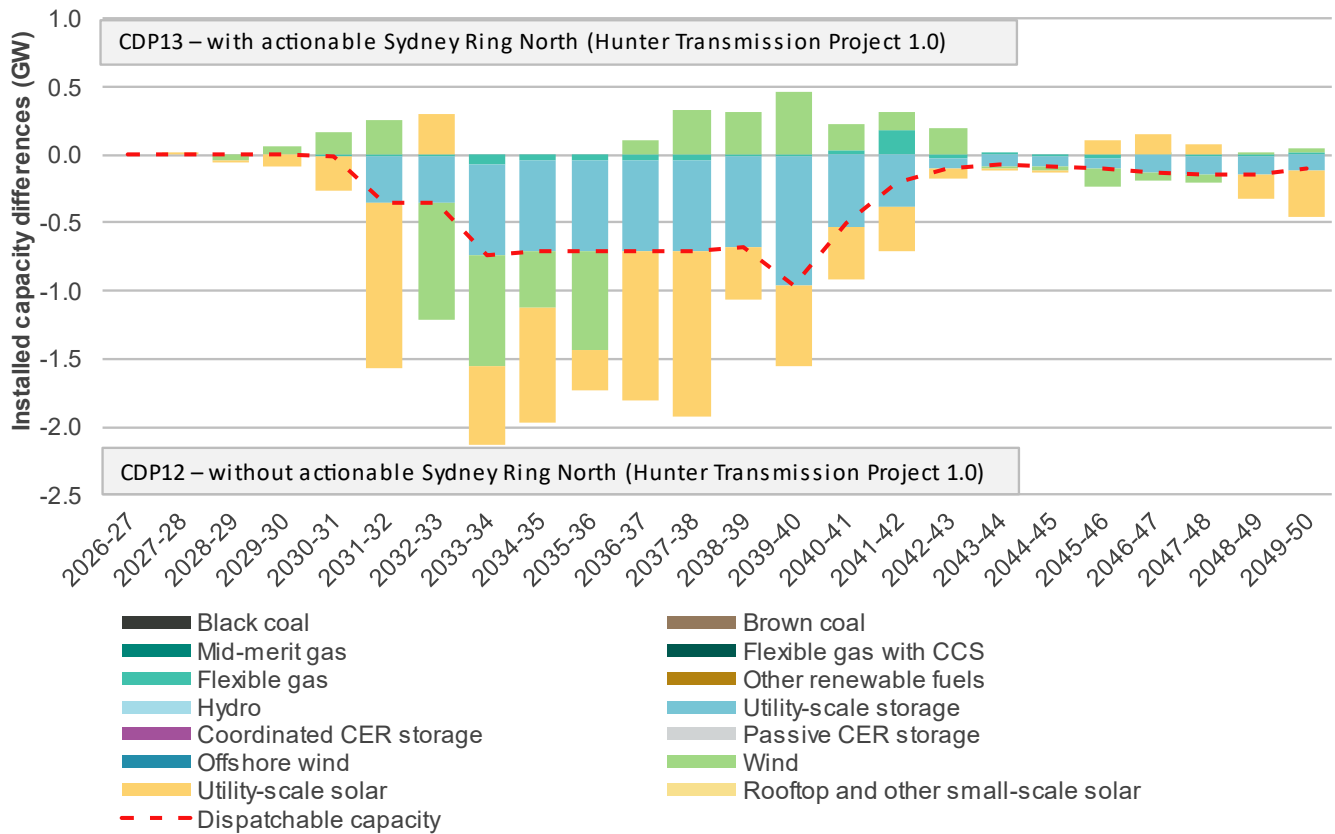
**Table 31 Comparing net market benefits between CDP13 and CDP12 (\$ billion) – Sydney Ring North (Hunter Transmission Project 1.0)**

	CDP13 – with actionable Sydney Ring North (Hunter Transmission Project 1.0)	CDP12 – without actionable Sydney Ring North (Hunter Transmission Project 1.0)	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.58	12.33	-0.25
<i>Step Change</i>	25.41	24.34	-1.07
<i>Accelerated Transition</i>	33.20	29.12	-4.08
<b>Weighted net market benefits</b>	24.05	22.39	-1.66
<b>Ranking based on weighted net market benefits</b>	11	21	N/A

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

As shown above in **Table 31**, an actionable Sydney Ring North (Hunter Transmission Project 1.0) delivers benefits across all scenarios and has a weighted net market benefit of \$1,663 million. These benefits are primarily driven by savings in generator and storage capital expenditure, and to a lesser extent, fuel costs and fixed operating and maintenance costs. In *Step Change*, delaying the project to after its actionable window would require an additional 700 MW of utility-scale storage, mostly in New South Wales, to be developed by the mid-2030s along with over 1.5 GW of additional VRE capacity.

**Figure 23 Comparison of capacity with and without Sydney Ring North (Hunter Transmission Project 1.0) in Step Change**



The reduction in relative market benefits is more pronounced in *Accelerated Transition*, which features faster New South Wales coal retirements and higher electricity consumption compared with *Step Change*. In *Accelerated Transition*, a delayed Sydney Ring North (Hunter Transmission Project 1.0) to after its actionable window would require an additional 5 GW of utility-scale storage and 4.6 GW of VRE. These additional generation and storage investments drive an overall increase in cost of \$4,085 million in this scenario.

### Assessing the regrets associated with Sydney Ring North (Hunter Transmission Project 1.0) as an actionable project

The weighted regrets of an actionable and non-actionable Sydney Ring North (Hunter Transmission Project 1.0) are presented in **Table 32**. Delaying the project until after its actionable window is regretful in all scenarios, with the worst weighted regret driven by under-investment in *Accelerated Transition* – from \$68 million to \$1,103 million.

**Table 32 Weighted and worst weighted regrets of CDP13 and CDP12 (\$ million) – Sydney Ring North (Hunter Transmission Project 1.0)**

	CDP13 – with actionable Sydney Ring North (Hunter Transmission Project 1.0)	CDP12 – without actionable Sydney Ring North (Hunter Transmission Project 1.0)	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	437	506	68
<i>Step Change</i>	34	526	492
<i>Accelerated Transition</i>	300	1,403	1,103
<b>Worst weighted regrets</b>	437	1,403	965
<b>Ranking based on worst weighted regrets</b>	7	21	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 controller option	500 kV option (Stage 1)	500 kV option (Stage 2)
<b>EISD</b>	July 2030	July 2034	July 2034
<b>Actionable window length</b>	4 years (actionable in 2024 ISP)		
<b>Cost</b>	\$269 million ( <i>Slower Growth</i> , 2030-31) \$269 million ( <i>Step Change</i> , 2030-31) \$274 million ( <i>Accelerated Transition</i> , 2030-31)	\$2,285 million ( <i>Step Change</i> , 2038-39) \$2,174 million ( <i>Accelerated Transition</i> , 2034-35)	\$646 million ( <i>Step Change</i> , 2038-39) \$645 million ( <i>Accelerated Transition</i> , 2034-35)
<b>Flow path or REZ</b>	CNSW-SNW South	CNSW-SNW South	CNSW-SNW South
<b>Capacity increase</b>	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 1.0), Sydney Ring South improves supply to the Sydney, Newcastle and Wollongong sub-region, which is increasingly important following New South Wales coal plant closures and to accommodate growth in electricity consumption. This power flow controller option project was previously found actionable in the 2024 ISP, giving it an actionable window length of four years.

The smaller power flow controller development 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 capability to transfer energy into Sydney, Newcastle and Wollongong from Southern New South Wales by improving the use of the southern and northern segments of the Central New South Wales to Sydney, Newcastle and Wollongong flow path. It is found to be optimal at its EISD of July 2030 in all three scenarios, as opposed to delaying at least four years to be outside its actionable window.

A subsequent, larger 500 kV option for Sydney Ring South is identified as a future ISP project, although it would be optimal at its EISD of July 2034 in *Accelerated Transition* and immediately after its actionable window in July 2038 in *Step Change*, delivering net market benefits in both scenarios. 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. This option also has a four-year actionable window since it can address the same identified need as the power flow controller option.

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

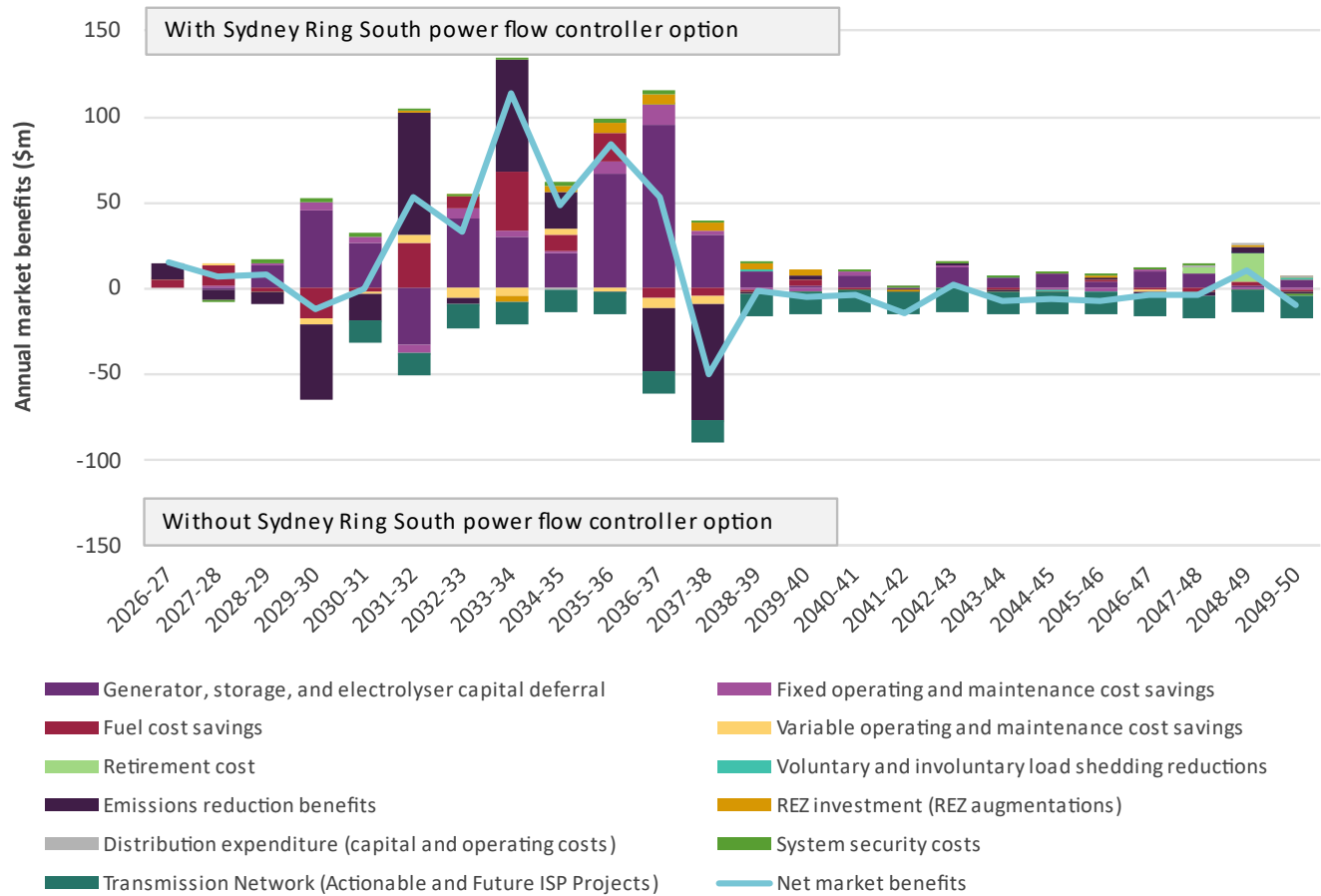
As seen in **Table 33**, the relative market benefits of Sydney Ring South power flow controller option in *Step Change* amount to \$183 million. Its gross benefits come primarily from generator and storage capital deferral savings.

**Figure 24** presents the annual relative market benefits. These are concentrated over the period to 2037-38 when the absence of the project is most impactful. The ODP and the Sydney Ring South power flow controller option TOOT in *Step Change* both have the larger 500 kV Sydney Ring South option (Stages 1 and 2) developed by 2037-38 (outside its actionable window). As a result, the cost of not having the smaller option in the TOOT is largely negated in the longer term but is significant in the medium term.

**Table 33** Relative market benefits of Sydney Ring South power flow controller option in *Step Change*

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	197
Fixed operating and maintenance cost savings	21
Fuel cost savings	46
Variable operating and maintenance cost savings	-9
Retirement cost	4
Voluntary and involuntary load shedding reductions	1
Emissions reduction benefits	1
REZ investment (REZ augmentations)	12
Distribution expenditure (capital and operating costs)	-0
System security costs	12
<b>Gross market benefits</b>	<b>283</b>
Transmission Network (Actionable and Future ISP Projects)	-99
<b>Total net market benefits</b>	<b>183</b>

**Figure 24 Annual relative market benefits of Sydney Ring South in Step Change (2030-31)**



The absence of Sydney Ring South power flow controller option leads to increased development of utility-scale storage and solar developments in Central Queensland and wind in Central New South Wales to leverage the transfer capability provided by Sydney Ring North (Hunter Transmission Project 1.0). The more efficient development of Sydney Ring South power flow controller option allows for improved sharing of electricity between the northern and southern segments of the CNSW-SNW flow path, effectively allowing more generation into the SNW sub-region from South New South Wales. This results in greater resource diversity with utility-scale solar in Southern New South Wales and utility-scale storage in the SNW sub-region. It also improves the ability for Victoria and Southern New South Wales generation (including existing hydro) to flow into Central New South Wales and Sydney, Newcastle and Wollongong.

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

A comparison of CDP4, which has Sydney Ring South power flow controller option as an actionable project, with CDP13, which delays it to a non-actionable timing, demonstrates the benefits of this project. **Table 34** shows that delivery of Sydney Ring South power flow controller option at an actionable timing would yield positive benefits in all scenarios and \$146 million in weighted net market benefits.

**Table 34 Comparing net market benefits between CDP4 and CDP13 (\$ billion) – Sydney Ring South power flow controller option**

	CDP4 – with actionable Sydney Ring South power flow controller option	CDP13 – without actionable Sydney Ring South power flow controller option	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.58	-0.05
<i>Step Change</i>	25.48	25.41	-0.07
<i>Accelerated Transition</i>	33.57	33.20	-0.37
<b>Weighted net market benefits</b>	24.20	24.05	-0.15
<b>Ranking based on weighted net market benefits</b>	1	11	N/A

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 Sydney Ring South – 500 kV option as an actionable project

AEMO has also examined whether it appropriate to identify the larger Sydney Ring South – 500 kV option (Stage 1 and Stage 2) as actionable. A comparison between CDP6, which has both stages actionable, and CDP4, which has neither stage as actionable enables this assessment (with both having the power flow controller option installed first). While the project would provide positive benefits at its EISD in *Accelerated Transition* due to the higher overall energy consumption and faster coal retirements in that scenario, **Table 35** shows that, across scenarios, delivering it at an actionable timing would result in a \$21 million reduction in weighted net market benefits. Therefore, it has been identified as a future ISP project rather than an actionable project.

**Table 35 Comparing net market benefits between CDP6 and CDP4 (\$ billion) – Sydney Ring South – 500 kV option (both stages)**

	CDP6 – with actionable Sydney Ring South – 500 kV option (both stages)	CDP4 – without actionable Sydney Ring South – 500 kV option (both stages)	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.42	12.64	0.22
<i>Step Change</i>	25.35	25.48	0.13
<i>Accelerated Transition</i>	33.94	33.57	-0.37
<b>Weighted net market benefits</b>	24.18	24.20	0.02
<b>Ranking based on weighted net market benefits</b>	2	1	N/A

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 regrets associated with Sydney Ring South as an actionable project

As seen in **Table 36**, delaying Sydney Ring South power flow controller option to a non-actionable timing leads to increased regrets in all scenarios. Overall, it results in a slight increase in worst weighted regret associated with under-investment in *Slower Growth* by \$14 million.

**Table 36** Weighted and worst weighted regrets of CDP4 and CDP13 (\$ million) – Sydney Ring South power flow controller option

	CDP4 – with actionable Sydney Ring South power flow controller option	CDP13 – without actionable Sydney Ring South power flow controller option	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	437	14
<i>Step Change</i>	2	34	32
<i>Accelerated Transition</i>	200	300	100
<b>Worst weighted regrets</b>	423	437	14
<b>Ranking based on worst weighted regrets</b>	5	7	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

<b>EISD</b>	July 2029
<b>Actionable window length</b>	2 years (not previously actionable)
<b>Cost</b>	\$227 million ( <i>Slower Growth</i> , 2029-30) \$233 million ( <i>Step Change</i> , 2031-32) \$231 million ( <i>Accelerated Transition</i> , 2029-30)
<b>Flow path or REZ</b>	SNSW-CNSW
<b>Capacity increase</b>	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 July 2029 in the least-cost DPs for *Slower Growth* and *Accelerated Transition* and just beyond its actionable window in July 2031 in *Step Change*.

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

**Table 37** 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 \$335 million of benefits identified are generator and storage capital savings as well as maintenance and fuel cost savings.

The project delays additional installed capacity in Central and Northern New South Wales and reduces the need to import energy from Queensland by improving access to renewable capacity developed in Southern 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	313
Fixed operating and maintenance cost savings	40
Fuel cost savings	26
Variable operating and maintenance cost savings	-5
Retirement cost	1
Voluntary and involuntary load shedding reductions	3
Emissions reduction benefits	1
REZ investment (REZ augmentations)	31
Distribution expenditure (capital and operating costs)	3
Gas system costs	0
System security costs	14
<b>Gross market benefits</b>	<b>428</b>
Transmission Network (Actionable and Future ISP Projects)	-92
<b>Total net market benefits</b>	<b>335</b>

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 CDP2, based on the least-cost DP for *Step Change* where it is not at its actionable timing, and CDP4, which also features delivery of Switching Station Near Wondalga its EISD. This comparison, in **Table 38**, shows that an actionable project would deliver an increase in weighted net market benefits of \$34 million, with the benefits primarily accruing due to the more significant benefit in *Accelerated Transition*.

**Table 38 Comparing net market benefits between CDP4 and CDP2 (\$ billion) – Switching Station Near Wondalga**

	CDP4 – with actionable Switching Station Near Wondalga	CDP2 – without actionable Switching Station Near Wondalga	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.64	0.00
<i>Step Change</i>	25.48	25.48	0.00
<i>Accelerated Transition</i>	33.57	33.43	-0.14
<b>Weighted net market benefits</b>	<b>24.20</b>	<b>24.16</b>	<b>-0.03</b>
<b>Ranking based on weighted net market benefits</b>	<b>1</b>	<b>5</b>	<b>NA</b>

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 marginal reduction in benefits in *Slower Growth* and *Step Change*, the overall increase in weighted net market benefits is driven by a \$136 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 delayed, as well as small increases in fuel cost from additional coal and gas generation.

Assessing the regrets associated with 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 *Accelerated Transition*, the worst weighted regrets in both CDP4 and CDP2, despite marginally decreasing, are still coming from the outcomes in *Slower Growth*. This therefore leads to worst weighted regret reducing slightly (by just \$1 million) when the project is has a non-actionable delivery.

**Table 39 Weighted and worst weighted regrets of CDP4 and CDP2 (\$ million) – Switching Station Near Wondalga**

	CDP4 – with actionable Switching Station Near Wondalga	CDP2 – without actionable Switching Station Near Wondalga	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	422	-1
<i>Step Change</i>	2	0	-2
<i>Accelerated Transition</i>	200	237	37
<b>Worst weighted regrets</b>	423	422	-1
<b>Ranking based on worst weighted regrets</b>	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.

## Victoria – New South Wales Interconnector West (VNI West)

<b>EISD</b>	November 2031
<b>Actionable window length</b>	8 years (actionable in 2020, 2022 and 2024 ISPs)
<b>Cost</b>	\$7,764 million ( <i>Slower Growth</i> , 2031-32) \$7,627 million ( <i>Step Change</i> , 2031-32) \$7,704 million ( <i>Accelerated Transition</i> , 2031-32)
<b>Flow path or REZ</b>	WNV-SNSW
<b>Capacity increase</b>	1,890 MW forward / 1,670 MW reverse

Victoria – New South Wales Interconnector West (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.

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 \$7,035 million<sup>32</sup> in 2029-30. It also provides efficient access to North West Victoria and South West New South Wales REZs.<sup>33</sup>

<sup>32</sup> 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 that should be excluded from the cost estimate for the 2026 ISP in accordance with the AER’s CBA Guidelines.

<sup>33</sup> The option of staging the required South West NSW REZ upgrade and wider VNI West project was tested in the least-cost development path assessment but ultimately found to be more costly to the system. More information is in Section A6.4.

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

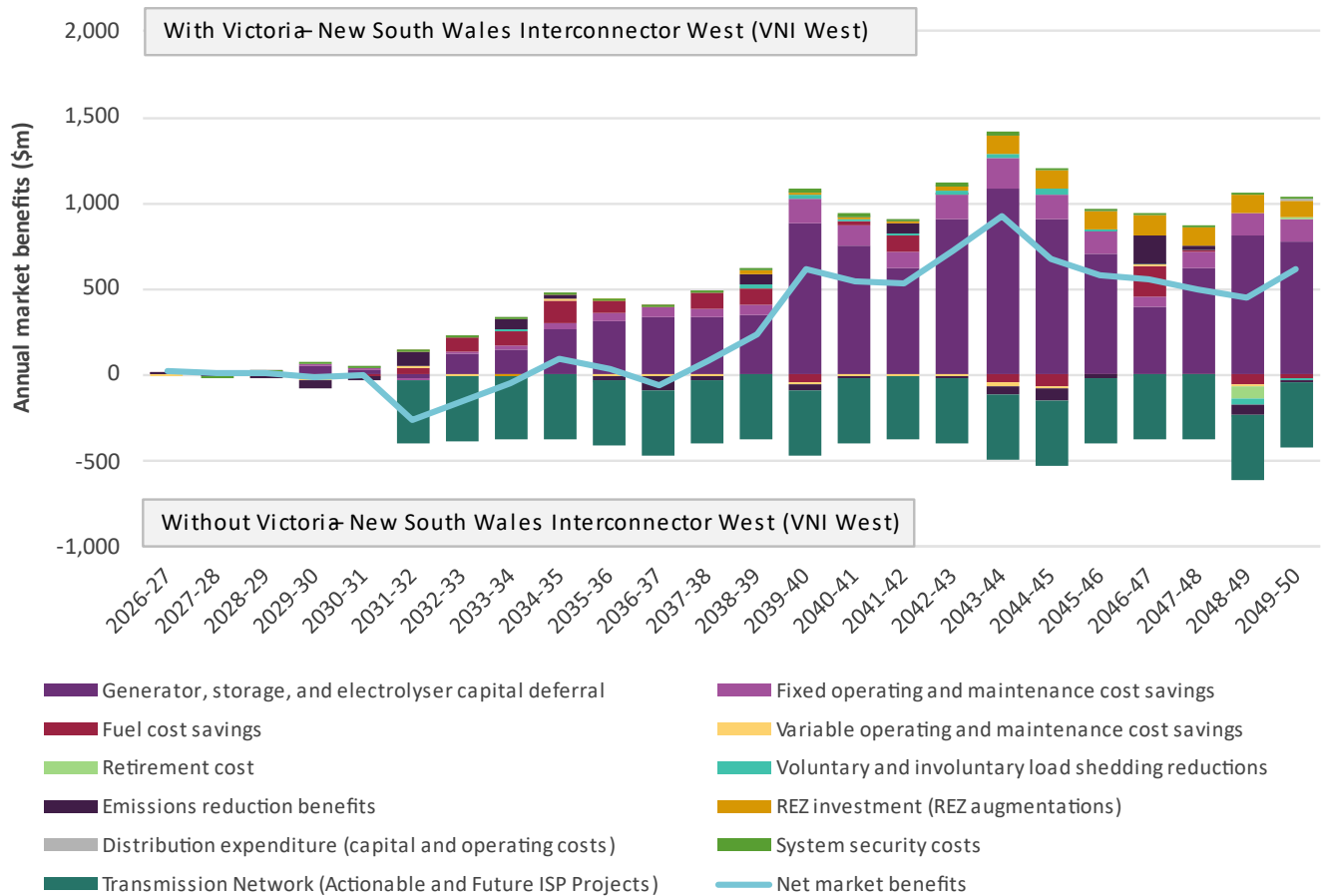
**Table 40** highlights the relative market benefits that a VNI West delivered at its EISD provides, relative to it never being developed. These benefits result mainly from generator and storage capital and maintenance deferral and fuel costs savings to a lesser extent. Overall, VNI West contributes approximately \$1.7 billion in net market benefits – with savings compounding further into the outlook period, as demonstrated by **Figure 25**. This is despite a nearly doubling of capital costs since the 2024 ISP.

Without VNI West, around 1.2 GW of flexible gas would be needed in Victoria, as well as 3 GW of utility-scale solar capacity in Victoria and South Australia, and 3 GW of wind capacity in New South Wales later in the 2040s. 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 Victoria – New South Wales Interconnector West (VNI West) in Step Change**

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	3,190
Fixed operating and maintenance cost savings	504
Fuel cost savings	312
Variable operating and maintenance cost savings	-30
Retirement cost	-12
Voluntary and involuntary load shedding reductions	47
Emissions reduction benefits	1
REZ investment (REZ augmentations)	203
Distribution expenditure (capital and operating costs)	2
System security costs	68
<b>Gross market benefits</b>	<b>4,285</b>
Transmission Network (Actionable and Future ISP Projects)	-2,586
<b>Total net market benefits</b>	<b>1,700</b>

**Figure 25 Annual relative market benefits of Victoria – New South Wales Interconnector West (VNI West) in Step Change (2030-31)**



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

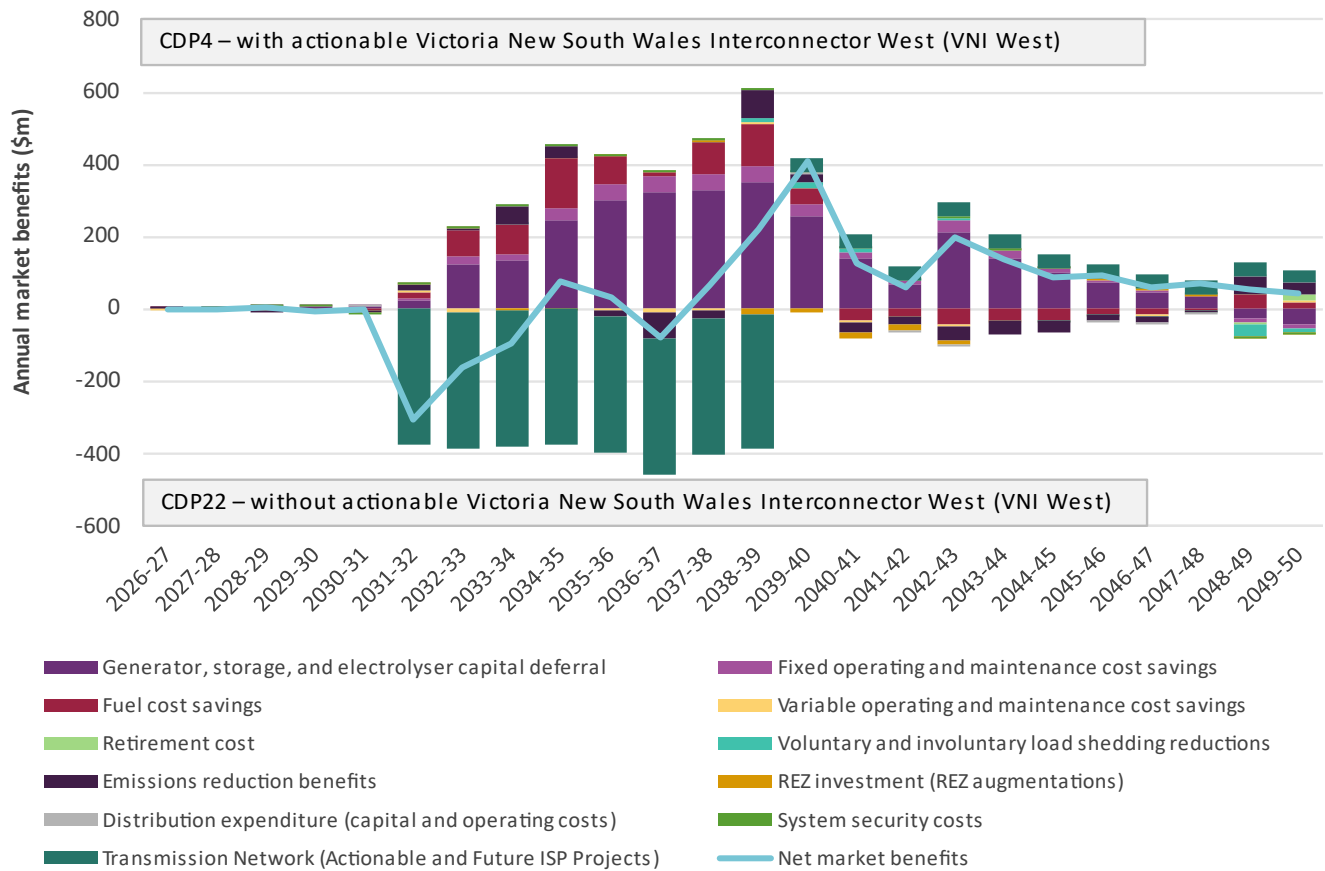
The benefits of VNI West as an actionable project can be assessed by comparing CDP4 with CDP22 (which features a delay to VNI West delivery to 2039-40 – outside its actionable window). As **Table 41** shows, delivering VNI West at its actionable timing provides \$769 million in weighted net market benefits. 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 CDP4 and CDP22 (\$ billion) – Victoria – New South Wales Interconnector West (VNI West)**

	CDP4 – with actionable VNI West	CDP22 – without actionable VNI West	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	11.73	-0.91
<i>Step Change</i>	25.48	25.28	-0.20
<i>Accelerated Transition</i>	33.57	31.97	-1.60
<b>Weighted net market benefits</b>	24.20	23.43	-0.77
<b>Ranking based on weighted net market benefits</b>	1	17	N/A

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

**Figure 26 Annual net market benefits associated with an actionable Victoria – New South Wales Interconnector West (VNI West), Step Change**



In *Step Change*, delaying the delivery of VNI West to outside the actionable window results in the earlier development of 1.3 GW of flexible gas in in the Greater Melbourne and Geelong sub-region to provide firm capacity and ensure energy supply during peak demand periods. This results in an increase in generation, fuel, and emissions costs over the period of the delay. Furthermore, Victorian offshore wind and Tasmanian hydro generation, which would otherwise be used to 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 wind capacity in those regions is brought forward. Developments of utility-scale solar capacity in New South Wales, partly associated with augmentation in the South West NSW REZ that accompanies VNI West, are delayed until the project is delivered.

Under *Slower Growth*, an additional 2 GW of wind generation capacity is brought forward in New South Wales and 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 these states, approximately 2 terawatt hours (TWh) per annum of additional black coal generation is required during the 2030s 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 reduces additional firm capacity requirement and relieves export constraints from Victoria. By addressing these limitations, VNI West enables greater transfer capability and

system flexibility which supports the accelerated integration of renewable generation and improves overall network resilience.

Assessing the regrets associated with 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 \$245 million, which comes from the risks of under-investment in *Slower Growth*.

**Table 42 Weighted and worst weighted regrets of CDP4 and CDP22 (\$ million) – Victoria – New South Wales Interconnector West (VNI West)**

	CDP4 – with actionable VNI West	CDP22 – without actionable VNI West	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	668	245
<i>Step Change</i>	2	94	91
<i>Accelerated Transition</i>	200	633	433
<b>Worst weighted regrets</b>	423	668	245
<b>Ranking based on worst weighted regrets</b>	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.

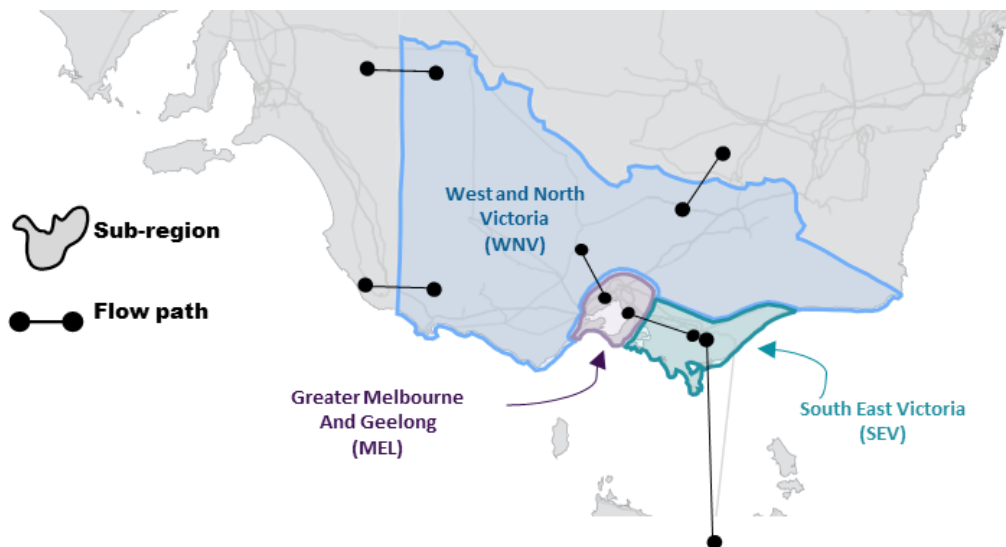
### Western Victoria Reinforcement program

EISD	June 2029
<b>Actionable window length</b>	2 years (not previously actionable)
<b>Cost</b>	\$139 million ( <i>Slower Growth</i> , 2040-41) \$130 million ( <i>Step Change</i> , 2028-29) \$132 million ( <i>Accelerated Transition</i> , 2028-29)
<b>Flow path or REZ</b>	MEL-WNV
<b>Capacity increase</b>	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 increased its representation of both regions, splitting Victoria into three sub-regions enabling greater analysis of flows between the Greater Melbourne and Geelong (MEL) sub-region and West and North Victoria (WNV) sub-region. **Figure 27** below shows this flow path in a map.



**Figure 27 Sub-regional representation of Victoria**



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. As this project has not been declared as actionable in any previous ISP, it has a two-year actionable window. 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* and *Accelerated Transition* as a future project delivering benefits at a non-actionable timing, as seen in **Table 18**.

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

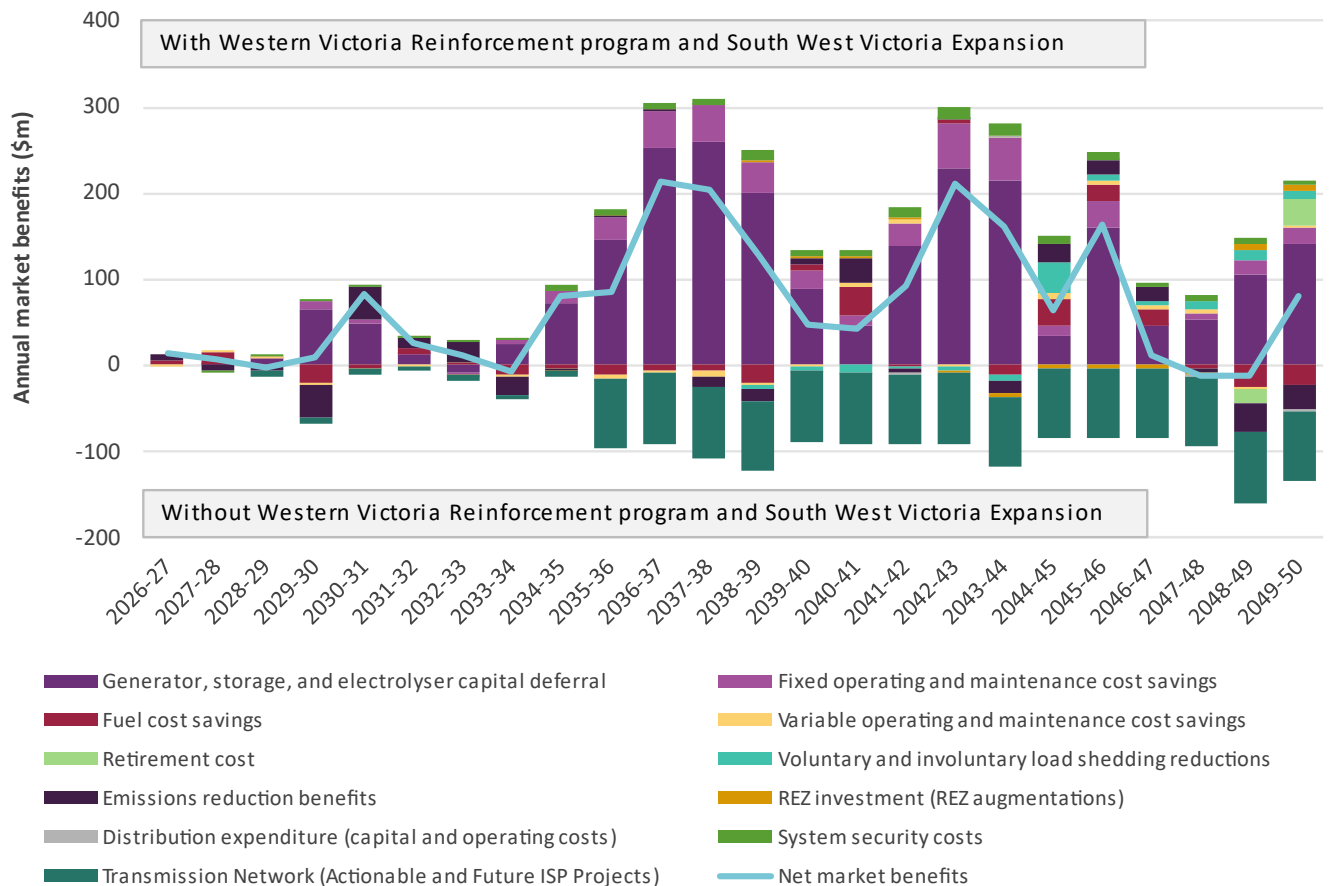
**Table 43** and **Figure 28** present the benefits of the Western Victoria Reinforcement program and its larger South West Victoria expansion program. Removing the Western Victoria Reinforcement program project would inhibit the development of the larger extension as well, as the Grid Reinforcement project is a pre-requisite, so this TOOT removed both projects in its analysis.

The majority of the \$642 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 2035-36)

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	840
Fixed operating and maintenance cost savings	151
Fuel cost savings	-5
Variable operating and maintenance cost savings	-4
Retirement cost	2
Voluntary and involuntary load shedding reductions	8
Emissions reduction benefits	1
REZ investment (REZ augmentations)	3
Distribution expenditure (capital and operating costs)	1
System security costs	51
<b>Gross market benefits</b>	<b>1,047</b>
Transmission Network (Actionable and Future ISP Projects)	-405
<b>Total net market benefits</b>	<b>642</b>

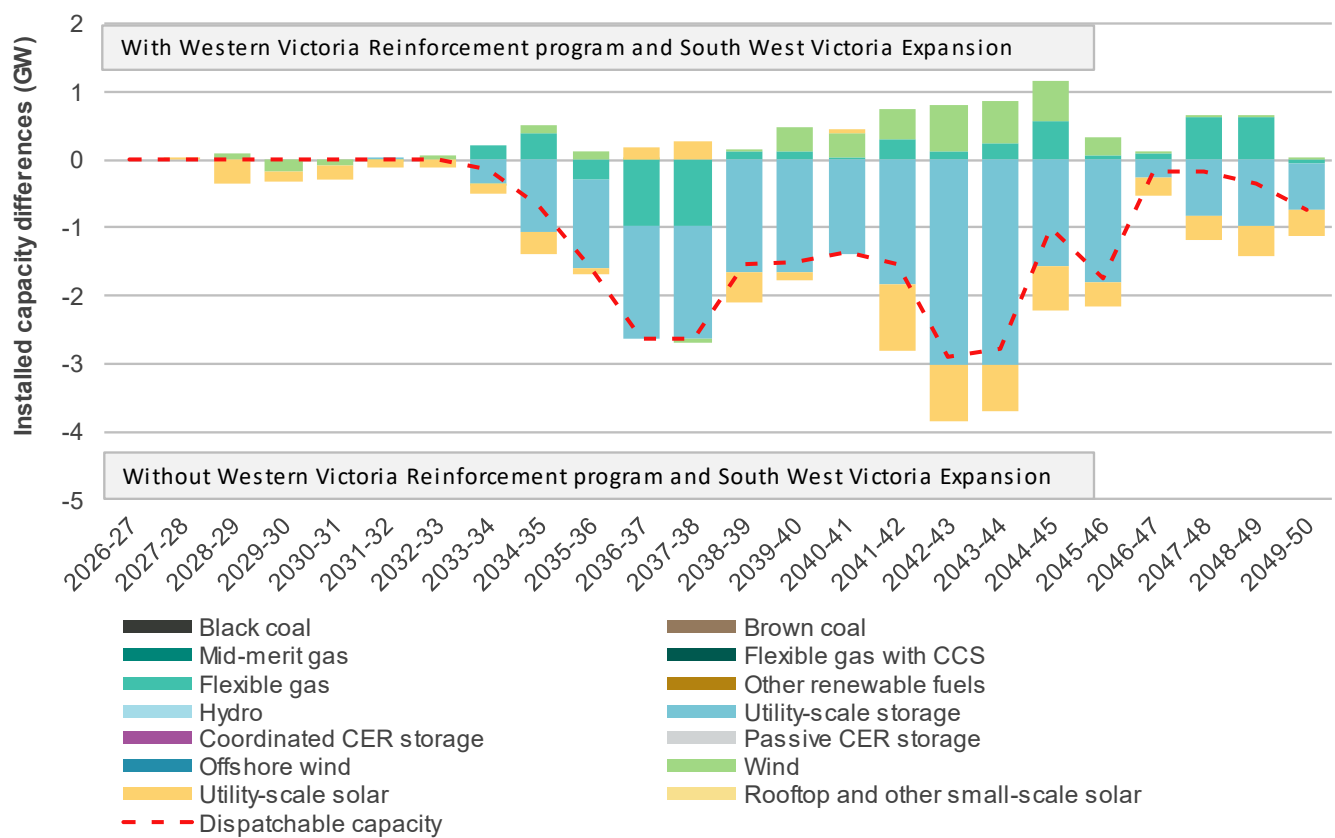
**Figure 28** Annual relative market benefits of Western Victoria Reinforcement program and South West Victoria Expansion in Step Change (2028-29 and 2035-36)



As seen in **Figure 29**, the smaller augmentation avoids some utility-scale solar capacity to be needed, but most of the benefits derived from the two options are due to avoiding the need for additional utility-scale storage and flexible gas capacity 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 29 Comparison of capacity with and without Western Victoria Reinforcement program and South West Victoria Expansion in Step Change (2028-29 and 2035-36)**



Assessing the net market benefits of Western Victoria Reinforcement program as an actionable project CDP4 has delivery of the Western Victoria Reinforcement program at its EISD, whereas CDP15 features it as a non-actionable project – its delivery is delayed by two years to 2031-32.

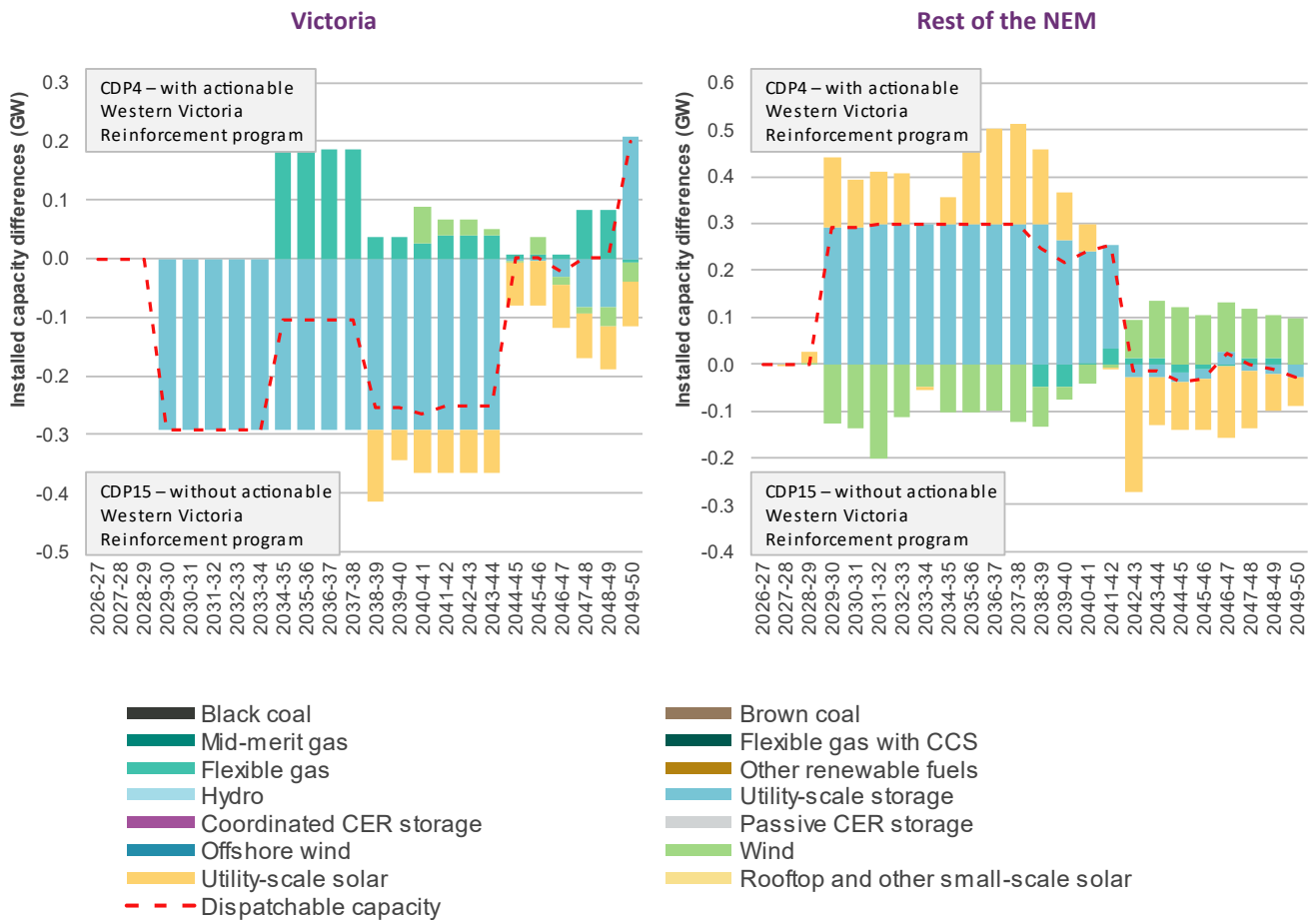
The benefits of an actionable Western Victoria Reinforcement program by scenario are shown in **Table 44** below. This analysis isolates the Grid Reinforcement project from the later larger augmentation discussed in the previous section.

**Table 44 Comparing net market benefits between CDP4 and CDP15 (\$ billion) – Western Victoria Reinforcement program**

	CDP4 – with actionable Western Victoria Reinforcement program	CDP15 – without actionable Western Victoria Reinforcement program	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.63	-0.01
<i>Step Change</i>	25.48	25.36	-0.12
<i>Accelerated Transition</i>	33.57	33.30	-0.27
<b>Weighted net market benefits</b>	24.20	24.07	-0.13
<b>Ranking based on weighted net market benefits</b>	1	10	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.

**Figure 30 Victoria capacity builds versus rest of the NEM in Step Change with and without an actionable Western Victoria Reinforcement program**



The project delivers net market benefits in *Step Change* and *Accelerated Transition* at \$115 million and \$272 million, respectively. When delayed until after its actionable window in *Step Change*, greater use of brown coal generation is observed, which increases system fuel and emissions costs, as well as earlier investment in renewable energy investments in South-East Victoria and alternate locations for storage capacity in New South Wales and Victoria that negatively impacts the development of complementary utility-scale solar capacity. This is demonstrated in **Figure 30** above. Similar

observations apply to *Accelerated Transition*, with greater VRE generation curtailment if Western Victoria Reinforcement program is delayed to after its actionable window.

The net market benefits of an actionable Western Victoria Reinforcement program in *Slower Growth* are much more marginal, as the WNV-MEL flow path is not as constrained in the earlier years of the forecast period without the augmentation if load growth and industrial load contraction occurs.

On a weighted basis across all three scenarios, the project delivers relative net market benefits of \$128 million.

Assessing the regrets associated with Western Victoria Reinforcement program as an actionable project **Table 45** presents the weighted regrets in each of the scenarios and worst weighted regrets for CDP4 and CDP15, with a non-actionable timing increasing regrets in all three scenarios. Delaying the project to a non-actionable timing increases weighted regret in *Accelerated Transition* by \$73 million, the most since it is in this scenario that the project delivers the most benefits.

**Table 45 Weighted and worst weighted regrets of CDP4 and CDP15 (\$ million) – Western Victoria Reinforcement program**

	CDP4 – with actionable Western Victoria Reinforcement program	CDP15 – without actionable Western Victoria Reinforcement program	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	425	2
<i>Step Change</i>	2	55	53
<i>Accelerated Transition</i>	200	274	73
<b>Worst weighted regrets</b>	423	425	2
<b>Ranking based on worst weighted regrets</b>	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.

## Gippsland Offshore Wind Transmission

	Stage 1	Stage 2 – Phase 1	Stage 2 – Phase 2
<b>EISD</b>	July 2031	July 2033	July 2038
<b>Actionable window length</b>	2 years (not previously actionable)	2 years (not previously actionable)	2 years (not previously actionable)
<b>Cost</b>	\$1,646 million ( <i>Slower Growth</i> , 2031-32) \$1,653 million ( <i>Step Change</i> , 2031-32) \$1,690 million ( <i>Accelerated Transition</i> , 2031-32)	\$892 million ( <i>Slower Growth</i> , 2033-34) \$901 million ( <i>Step Change</i> , 2033-34) \$925 million ( <i>Accelerated Transition</i> , 2033-34)	\$494 million ( <i>Slower Growth</i> , 2038-39) \$502 million ( <i>Step Change</i> , 2038-39) \$522 million ( <i>Accelerated Transition</i> , 2038-39)
<b>Flow path or REZ</b>	Gippsland Offshore REZ	Gippsland Offshore REZ and SEVIC1 Group REZ	Gippsland Offshore REZ and SEVIC1 Group REZ
<b>Capacity increase</b>	2,000 MW	2,000 MW (Gippsland Offshore REZ) and 2,000 MW (South-East Victoria group constraint <sup>A</sup> , SEVIC1)	3,000 MW (Gippsland Offshore REZ) and 4,600 MW (South-East Victoria group constraint <sup>A</sup> , 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<sup>34</sup>. 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. The first stage (Gippsland Offshore Wind Transmission Stage 1) has an EISD of 2031-32, costs \$1.7 billion, and would provide an initial 2000 MW of network capacity. The second stage (Gippsland Offshore Wind Transmission Stage 2 – Phase 1) has an EISD of 2033-34, costs \$892 million, and would provide an additional 2000 MW of network capacity in the Gippsland Offshore REZ, and 2,000 MW through South-East Victoria. The last stage (Gippsland Offshore Wind Transmission Stage 2 – Phase 2) has an expected cost of \$502 million in *Step Change* if delivered at its EISD of 2038-39 and would provide an additional 3,000 MW in Gippsland Offshore REZ and 4,600 MW through South-East Victoria of network capacity.

Neither of these stages has been declared actionable in previous ISPs, therefore all have an actionable window of two years.

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 discusses the relative net market benefits of all three projects via TOOT analysis, the merits of identifying both Stage 1 and Stage 2 – Phase 1 as actionable in isolation, and then lastly the merits of an actionable Stage 2 – Phase 2.

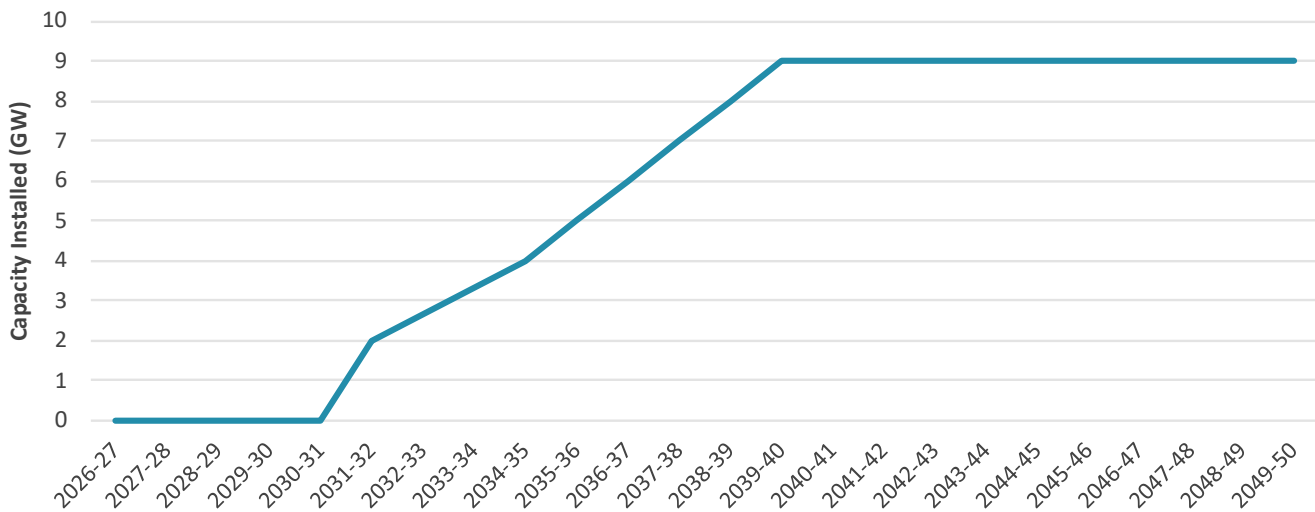
Assessing the relative market benefits of Gippsland Offshore Wind Transmission (Stage 1, Stage 2 – Phase 1 and Stage 2 – Phase 2) via TOOT analysis

**Table 47** 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. These benefits accrue mainly from the deferral of generator and storage capital expenditure, the maintenance cost savings this is accompanied by, and from fuel costs savings over the outlook period.

This analysis assumes that the Victorian Offshore Wind Target must be achieved according to the schedule shown in **Figure 31**, even in cases 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. Significant delays in the development of offshore wind capacities would impact the benefits of these projects. In general, the development of Gippsland Offshore Wind Transmission should coincide with the build out and scale of offshore wind resources in that REZ.

<sup>34</sup> At <https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/gippsland>.

**Figure 31 Assumed Victorian offshore wind development to meet Victorian Offshore Wind Target**

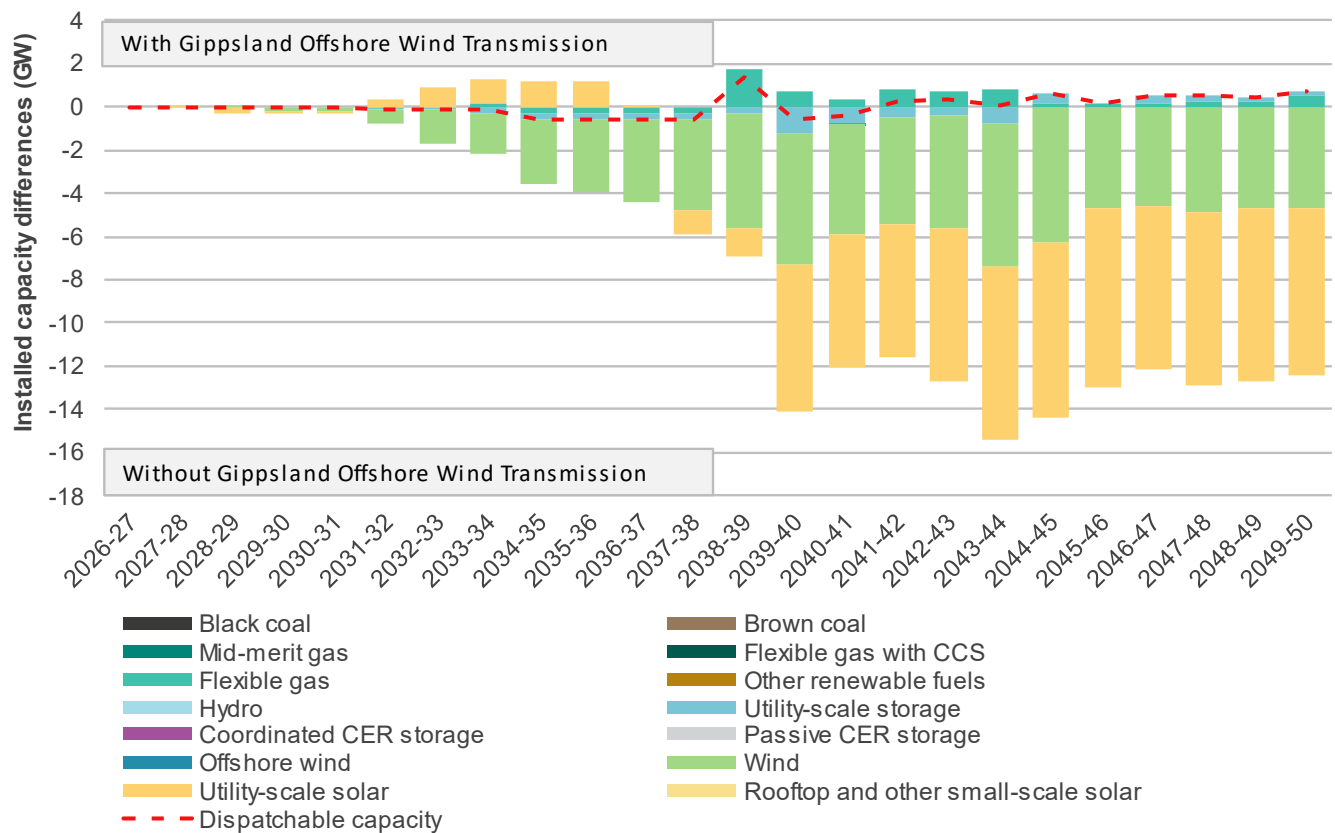


As shown below in **Figure 32**, delivery of projects avoids alternative developments of over 12 GW of utility-scale solar and wind across the outlook period which would otherwise need to be built to meet forecast energy consumption growth and to meet the Victorian Renewable Energy Target, saving significant capital investment.

**Table 46 Relative market benefits of Gippsland Offshore Wind Transmission (Stage 1, Stage 2 – Phase 1 and Stage 2 – Phase 2) in Step Change**

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	10,904
Fixed operating and maintenance cost savings	2,194
Fuel cost savings	367
Variable operating and maintenance cost savings	40
Retirement cost	4
Voluntary and involuntary load shedding reductions	84
Emissions reduction benefits	4
REZ investment (REZ augmentations)	277
Distribution expenditure (capital and operating costs)	19
System security costs	225
<b>Gross market benefits</b>	<b>14,118</b>
Transmission Network (Actionable and Future ISP Projects)	-867
<b>Total net market benefits</b>	<b>13,250</b>

**Figure 32 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 2032-33, 2034-35 and 2038-39, respectively)**



Note: Offshore wind development 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 and Stage 2 – Phase 1) as actionable projects

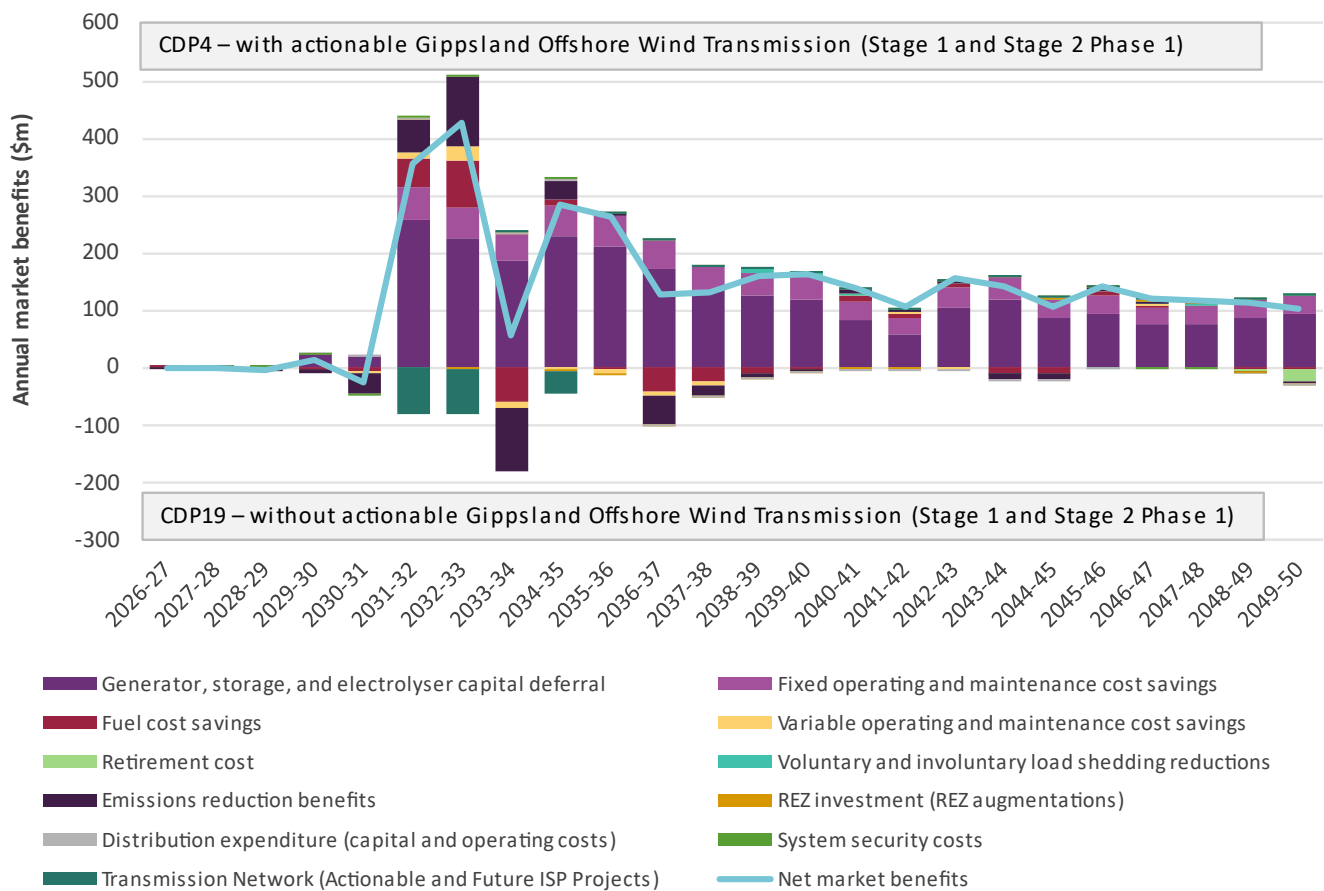
CDP4 delivers both earlier stages of the Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1) at their respective EISDs. CDP19 features delaying these projects to the first year outside of their actionable window (2033-34 for Stage 1 and 2035-36 for Stage 2 – Phase 1, respectively). The benefits of these projects being actionable by scenario is displayed below.

**Table 47 Comparing net market benefits between CDP4 and CDP19 (\$ billion) – Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)**

	CDP4 – with actionable Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)	CDP19 – without actionable Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.28	-0.35
<i>Step Change</i>	25.48	24.17	-1.31
<i>Accelerated Transition</i>	33.57	30.51	-3.06
<b>Weighted net market benefits</b>	24.20	22.67	-1.52
<b>Ranking based on weighted net market benefits</b>	1	20	N/A

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

**Figure 33 Net market benefits of Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1), Step Change**



An actionable Gippsland Offshore REZ Connection delivers a weighted net market benefit of \$1,524 million, with strong net market benefits demonstrated across all three scenarios. In all scenarios, these benefits come from deferring alternative renewable energy developments, and their complementary storages and avoiding additional gas and coal generation which would increase fuel and emissions costs.

It should be noted that across all scenarios, AEMO assumed that Victorian offshore wind is developed according to the schedule shown in **Figure 31**. Significant delays in the development of offshore wind capacities would impact the benefits of these 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 Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1) as actionable projects**

As **Table 48** shows, delaying Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1) until after the actionable windows of both projects increases regrets across all scenarios which consequently results in an increase in worst weighted regrets by \$602 million. The worst weighted regret is driven by not being able to fully utilise Victorian offshore wind generation in *Accelerated Transition*.

**Table 48** Weighted and worst weighted regrets of CDP4 and CDP19 (\$ million) – Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)

	CDP4 – with actionable Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)	CDP19 – without actionable Gippsland Offshore Wind Transmission (Stage 1 and Stage 2 – Phase 1)	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	519	95
<i>Step Change</i>	2	606	604
<i>Accelerated Transition</i>	200	1,025	825
<b>Worst weighted regrets</b>	423	1,025	602
<b>Ranking based on worst weighted regrets</b>	5	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.

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

The net market benefits of Gippsland Offshore Wind Transmission Stage 2 (Phase 2) can be observed by comparing CDP4 and CDP18, which delays the upgrade to after its actionable window in 2040-41. Note that both CDPs feature actionable timing for Gippsland Offshore Wind Transmission Stage 2 (Phase 1) given the benefits outlined in the previous section.

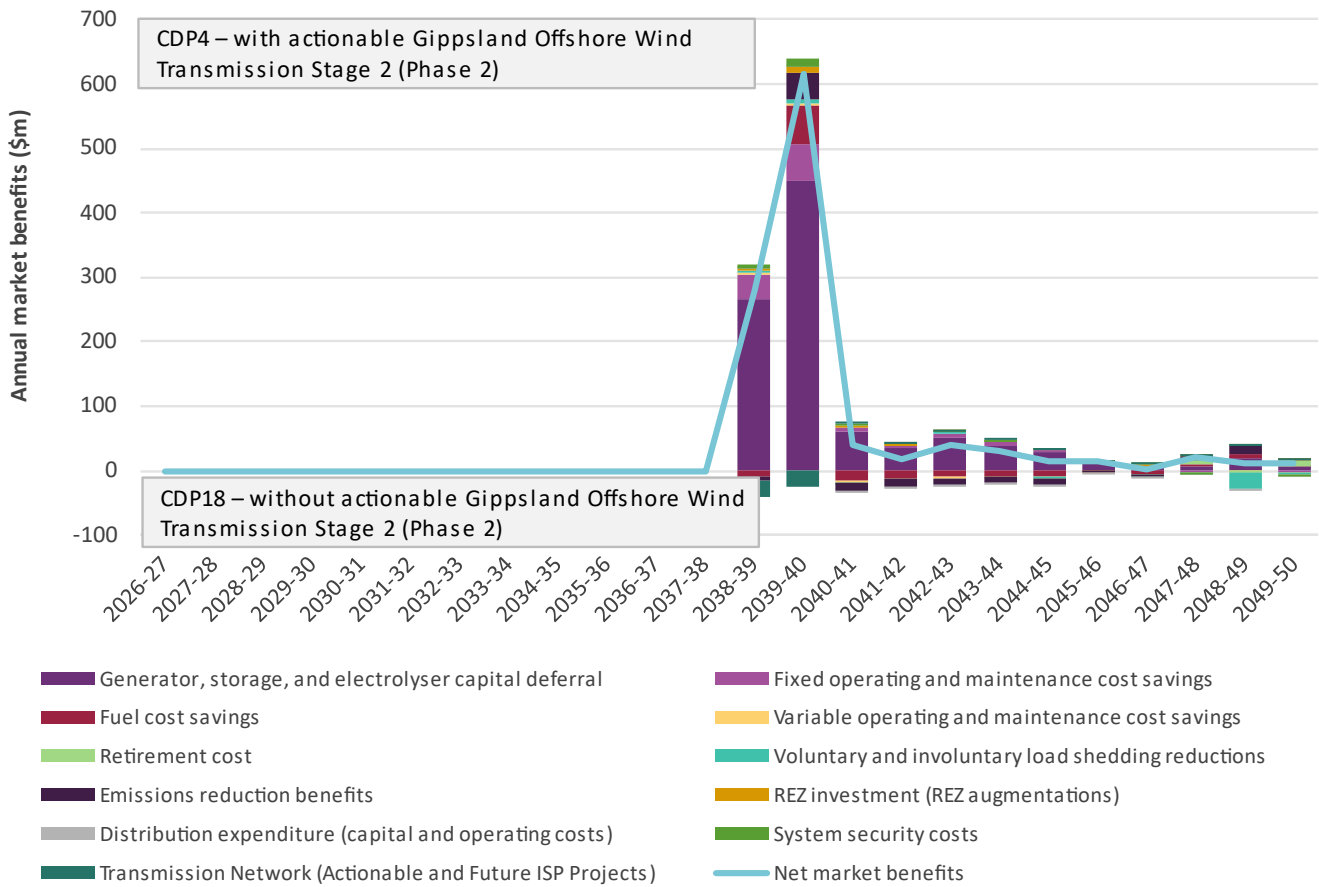
As **Table 49** shows, the project delivers significant benefits in each scenario – around \$209 million in *Slower Growth*, \$387 million in *Step Change*, and \$418 million in *Accelerated Transition*.

**Table 49** Comparing net market benefits between CDP4 and CDP18 (\$ billion) – Gippsland Offshore Wind Transmission Stage 2 (Phase 2)

	CDP4 – with actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	CDP18 – without actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.43	-0.21
<i>Step Change</i>	25.48	25.09	-0.39
<i>Accelerated Transition</i>	33.57	33.15	-0.42
<b>Weighted net market benefits</b>	24.20	23.85	-0.35
<b>Ranking based on weighted net market benefits</b>	1	15	N/A

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

**Figure 34 Annual net market benefits of Gippsland Offshore Wind Transmission Stage 2 (Phase 2) in Step Change**



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 supplied from Victorian offshore wind. In 2039-40, offshore wind curtailment hits 32% without this project compared with just 7% when the project is delivered at an actionable timing, and 2.4 GW of utility-scale wind and solar capacities, mostly in Victoria and Central New South Wales, are brought forward.

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 wind and solar capacity to be built but on a larger scale than that in *Step Change*. In *Slower Growth*, a delay of this project is less impactful to the timing of other new developments.

Assessing the regrets associated with Gippsland Offshore Wind Transmission Stage 2 (Phase 2) as an actionable project

**Table 50** 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) across all scenarios, but most noticeably in the *Step Change* scenario, resulting in an overall increase in worst weighted regret of \$56 million.

**Table 50** Weighted and worst weighted regrets of CDP4 and CDP18 (\$ million) – Gippsland Offshore Wind Transmission Stage 2 (Phase 2)

	CDP4 – with actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	CDP18 – without actionable Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	480	56
<i>Step Change</i>	2	180	178
<i>Accelerated Transition</i>	200	313	113
<b>Worst weighted regrets</b>	423	480	56
<b>Ranking based on worst weighted regrets</b>	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.

## Project Marinus Stage 2

<b>EISD</b>	December 2034
<b>Actionable window length</b>	8 years (actionable in 2020, 2022 and 2024 ISPs)
<b>Cost</b>	\$2,626 million (Slower Growth, 2034-35) \$2,626 million (Step Change, 2034-35) \$2,626 million (Accelerated Transition, 2034-35)
<b>Flow path or REZ</b>	TAS-SEV
<b>Capacity increase</b>	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 \$2,626 million in 2034-35<sup>35</sup>.

Given the advanced state of the development of Project Marinus Stage 1, this project was treated as anticipated in the Draft 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.

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

**Table 51** shows a \$273 million relative market benefits of delivering Project Marinus Stage 2 at its EISD in *Step Change* compared with a case without the project. The key source of benefits for this project is the deferral of over 1.4 GW of wind and utility-scale solar capacities to beyond 2049-50 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 (see **Figure 35**).

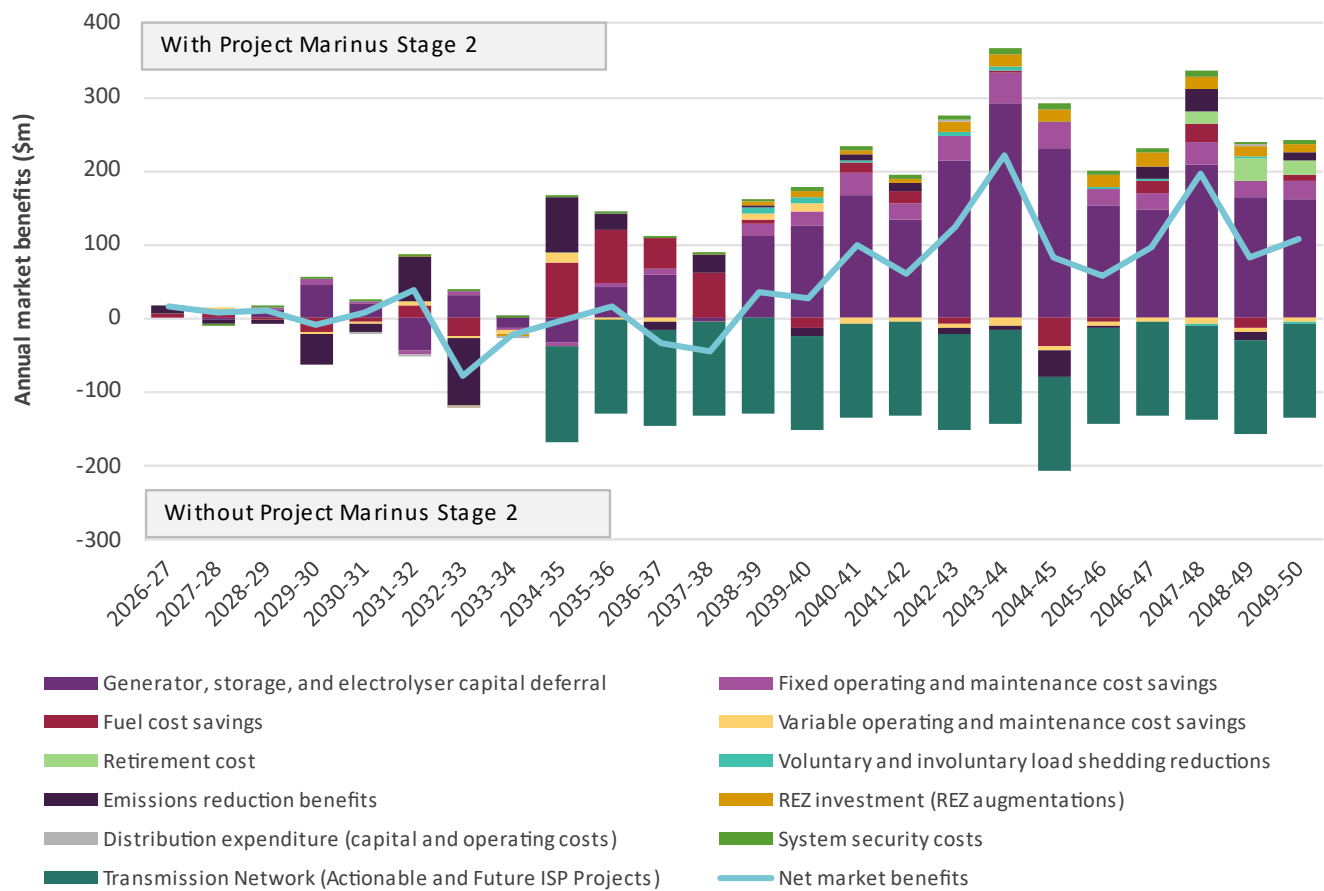
<sup>35</sup> The costs presented and used in the analysis exclude the amounts related to approved early works and other incurred costs that should be excluded from the cost estimate for the 2026 ISP in accordance with the AER’s CBA Guidelines. For more information, please see the 2025 *Electricity Network Options Report*.

In addition, approximately 500 TWh 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 significant fuel cost savings in the late 2030s and reduced system security costs.

**Table 51 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	637
Fixed operating and maintenance cost savings	99
Fuel cost savings	114
Variable operating and maintenance cost savings	-10
Retirement cost	13
Voluntary and involuntary load shedding reductions	12
Emissions reduction benefits	3
REZ investment (REZ augmentations)	34
Distribution expenditure (capital and operating costs)	1
System security costs	29
<b>Gross market benefits</b>	<b>933</b>
Transmission Network (Actionable and Future ISP Projects)	-659
<b>Total net market benefits</b>	<b>273</b>

**Figure 35 Comparison of capacity with and without Project Marinus Stage 2 actionable in Step Change (at 2034-35)**



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

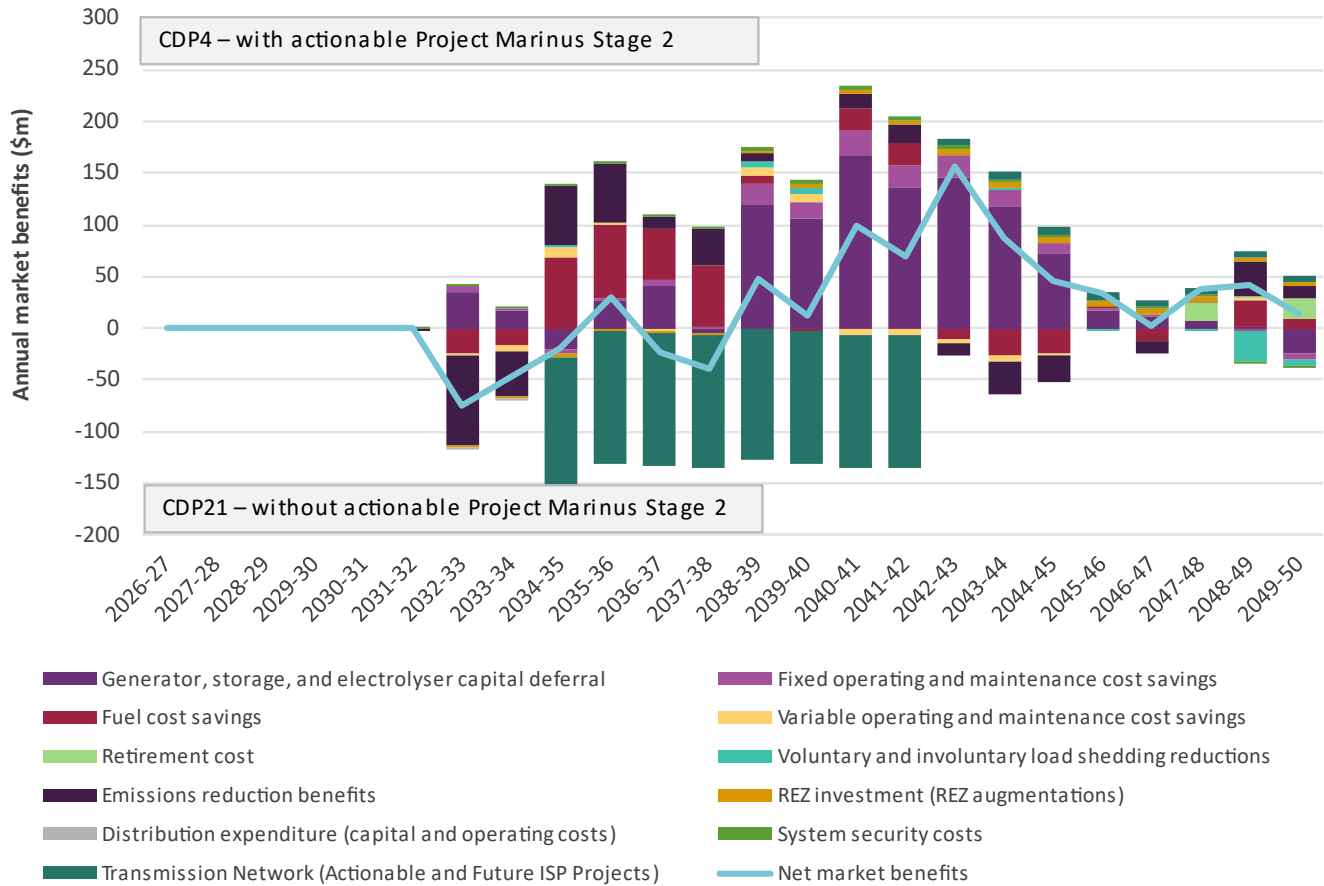
CDP4 has delivery of Project Marinus Stage 2 at its EISD, whereas CDP21 features delivery of the project in 2042-43 after Stage 2’s actionable window. The benefits of an actionable Project Marinus Stage 2 by scenario are displayed in **Table 52** below.

**Table 52 Comparing net market benefits between CDP4 and CDP21 (\$ billion) – Project Marinus Stage 2**

	CDP4 – with actionable Project Marinus Stage 2	CDP21 – without actionable Project Marinus Stage 2	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	11.33	-1.31
<i>Step Change</i>	25.48	25.38	-0.10
<i>Accelerated Transition</i>	33.57	33.08	-0.49
<b>Weighted net market benefits</b>	24.20	23.67	-0.53
<b>Ranking based on weighted net market benefits</b>	1	16	N/A

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

**Figure 36 Net market benefits of actionable Project Marinus Stage 2 in Step Change**



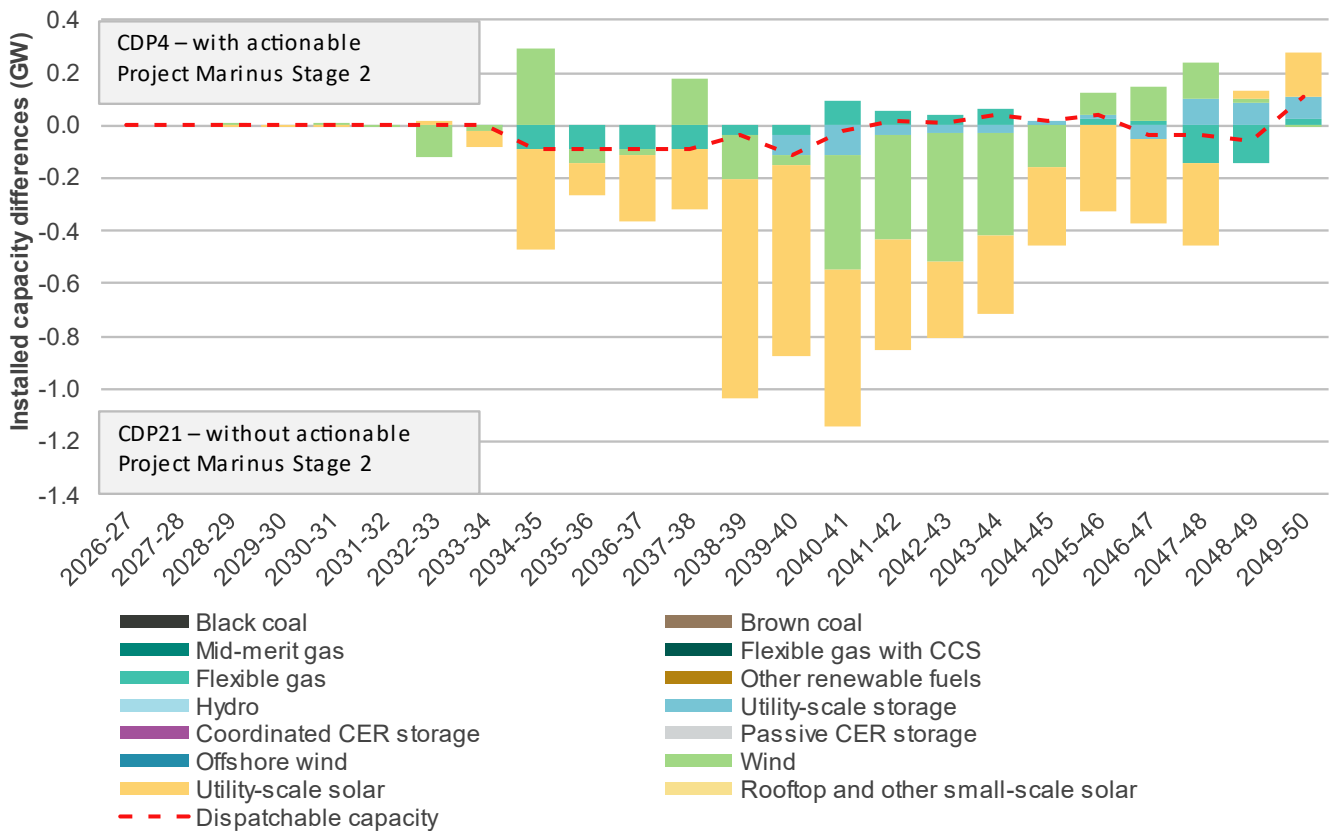
An actionable Project Marinus Stage 2 delivers market benefits across all scenarios – the strongest case coming from *Slower Growth* (\$1,305 million), followed by *Accelerated Transition* (\$486 million), then *Step Change* (\$96 million). On a weighted net market benefits basis, an actionable Project Marinus Stage 2 results in weighted net market benefits of \$528 million.

Project Marinus Stage 2 enables greater export of Tasmanian renewable energy capacity that is built to contribute to meeting the Tasmania Renewable Energy Target, providing the mainland with access to this generation in the 2030s and 2040s.

Delaying Project Marinus Stage 2 in *Step Change* requires building an additional 800 MW of wind and utility-scale solar capacities in Victoria in the late 2030s that would otherwise be built much later in the outlook period (see **Figure 37** below). It also misses the opportunity to deliver the significant cost savings identified in **Table 52** which leads to higher utilisation of gas generators around the NEM in the 2030s and associated increases in fuel and variable operating and maintenance costs for these existing generators.

Similar dynamics apply to *Accelerated Transition* but on a larger scale. In *Slower Growth*, 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. In *Slower Growth* the project also delays 300 MW of additional flexible gas capacity in the Greater Melbourne and Geelong sub-region that would otherwise be needed to provide reliable supply.

Figure 37 Comparison of capacity with and without an actionable Project Marinus Stage 2 in Step Change



Assessing the regrets associated with Project Marinus Stage 2 as an actionable project

Table 53 presents the weighted regrets and worst weighted regrets for CDP21 and CDP4 across all the scenarios. If the project’s delivery is delayed until after the actionable window, 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 \$352 million.

Table 53 Weighted and worst weighted regrets of CDP4 and CDP21 (\$ million) – Project Marinus Stage 2

	CDP4 – with actionable Project Marinus Stage 2	CDP21 – without actionable Project Marinus Stage 2	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	776	352
<i>Step Change</i>	2	46	44
<i>Accelerated Transition</i>	200	331	131
<b>Worst weighted regrets</b>	423	776	352
<b>Ranking based on worst weighted regrets</b>	5	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.



## Waddamana to Palmerston transfer capability upgrade

<b>EISD</b>	July 2030
<b>Actionable window length</b>	4 years (actionable in the 2024 ISP) <sup>36</sup>
<b>Cost</b>	\$238 million ( <i>Slower Growth</i> , 2030-31) \$240 million ( <i>Step Change</i> , 2030-31) \$245 million ( <i>Accelerated Transition</i> , 2030-31)
<b>Flow path or REZ</b>	Central Highlands REZ
<b>Capacity increase</b>	555 MW

The Waddamana to Palmerston transfer capability upgrade is an ISP project which increases transfer capacity from potential renewable generation development in Tasmania’s Central Highlands REZ. The project has an EISD of July 2030 and is identified to be best delivered at an actionable timing in each scenario. The option provides additional network capacity of 555 MW to support development of renewable generation in central Tasmania which would aid in meeting the region’s policy targets and energy consumption in the future.

In the 2024 ISP, an upgrade to this REZ was deemed as actionable. A new option provided by TasNetworks through joint planning with a much lower cost than the previously selected option, which does not require building any new transmission lines, is considered in this ISP.

### Assessing the relative market benefits of Waddamana to Palmerston transfer capability upgrade via TOOT analysis

As seen in **Table 54**, the delivery of the project at actionable timing provides relative market benefits of \$168 million in *Step Change*. Most of these savings are avoided generator capital costs from 400 MW of additional utility-scale solar capacity in Tasmania that would be needed to replace the energy curtailed from utility-scale wind and solar generation in the Central Highland REZ if the delivery of the Waddamana to Palmerston transfer capability upgrade is delayed to after its actionable window. Wind capacity development in Tasmania is also shifted in 2030-31 from the Central Highlands REZ towards North East Tasmania. The project also avoids the need for additional wind and utility-scale solar capacity in Victoria in the 2040s, as shown in **Figure 38**.

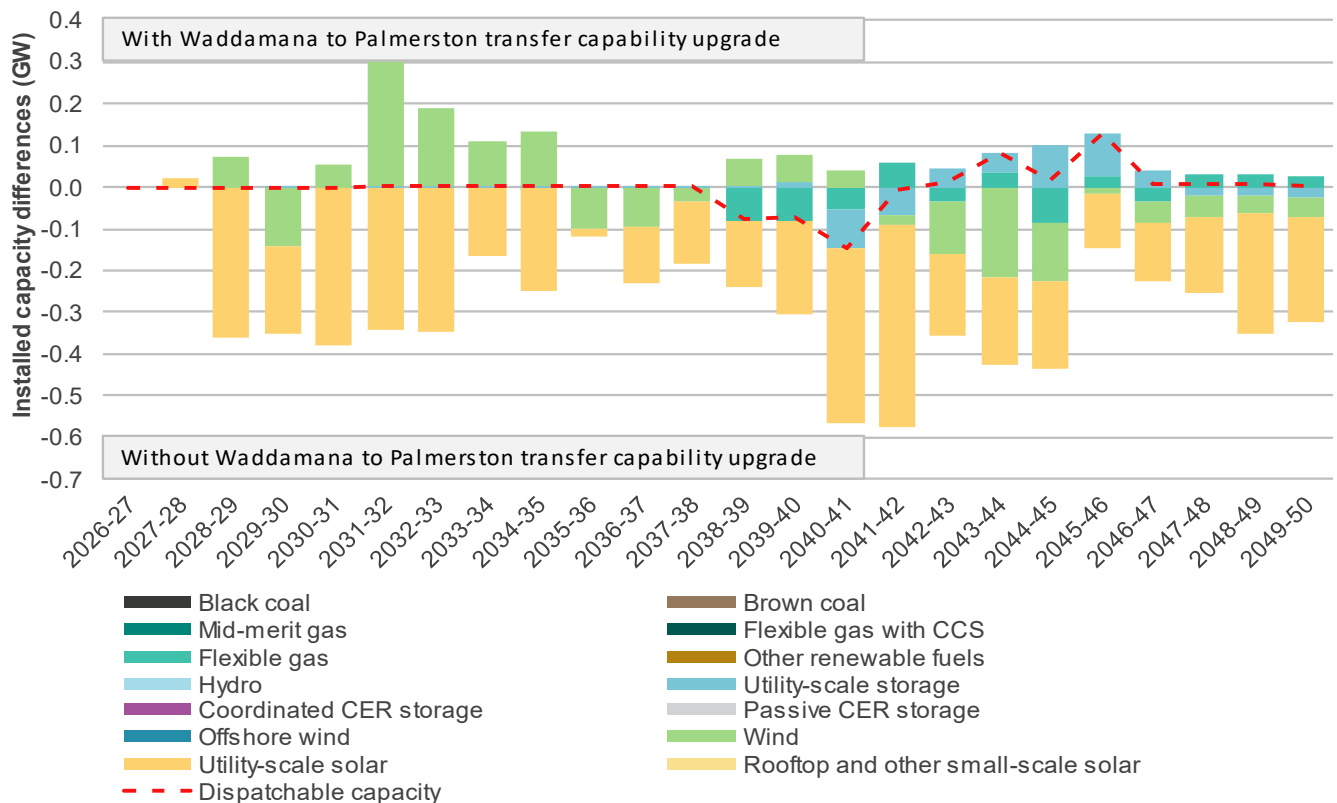
Without an upgrade to the Central Highlands REZ, additional utility-scale solar would become a critical source of renewable generation for Tasmania. However, with an existing distribution network export limit of only 400 MW for these resources, further distribution network augmentations are necessary to allow it to export at its full capacity without network curtailment. This subsequently drives an increase in distribution expenditure of \$45 million if the REZ upgrade was not developed.

<sup>36</sup> The 2024 ISP identified T3 Option 1, a new double-circuit line between Waddamana and Palmerston, as an actionable project. This Draft 2026 ISP identifies T3 Option 1A, a restringing of the existing Waddamana – Palmerston 110 kV line, as delivering more benefits. For the early and late comparison in this subsection, AEMO modelled a two-year actionable window instead of a four-year window. This will be rectified for the final 2026 ISP.

**Table 54** Relative market benefits of Waddamana to Palmerston transfer capability upgrade in Step Change

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	132
Fixed operating and maintenance cost savings	14
Fuel cost savings	28
Variable operating and maintenance cost savings	0
Retirement cost	6
Voluntary and involuntary load shedding reductions	-2
Emissions reduction benefits	1
REZ investment (REZ augmentations)	16
Distribution expenditure (capital and operating costs)	45
System security costs	17
<b>Gross market benefits</b>	<b>257</b>
Transmission Network (Actionable and Future ISP Projects)	-88
<b>Total net market benefits</b>	<b>168</b>

**Figure 38** Comparison of capacity with and without Waddamana to Palmerston transfer capability upgrade in Step Change (at 2029-30)



Assessing the net market benefits of Waddamana to Palmerston transfer capability upgrade as an actionable project

The net market benefits of the Waddamana to Palmerston transfer capability upgrade can be assessed by comparing CDP4 and CDP20 which delays the augmentation to after its actionable window. As **Table 55** highlights, the project delivers

positive benefits in *Step Change* (\$59 million) and *Accelerated Transition* (\$195 million) when delivered at an actionable timing, while there is a marginal reduction of benefits in *Slower Growth* of \$3 million.

**Table 55 Comparing net market benefits between CDP4 and CDP20 (\$ billion) – Waddamana to Palmerston transfer capability upgrade**

	CDP4 – with actionable Waddamana to Palmerston transfer capability upgrade	CDP20– without actionable Waddamana to Palmerston transfer capability upgrade	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	12.64	0.00
<i>Step Change</i>	25.48	25.42	-0.06
<i>Accelerated Transition</i>	33.57	33.37	-0.20
<b>Weighted net market benefits</b>	24.20	24.12	-0.08
<b>Ranking based on weighted net market benefits</b>	1	6	N/A

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 this project is delivered at a non-actionable timing in *Step Change*, over 100 MW of additional utility-scale solar capacity and expansion of the distribution network would be needed to meet the Tasmania Renewable Energy Target in 2040 instead of just a lower amount of utility-scale wind capacity in the Central Highlands REZ.

The other key benefit of the project is that it allows development of wind capacity in the Central Highlands REZ which is more efficient at producing energy compared with other locations in Tasmania.

Similar dynamics are observed in *Accelerated Transition*, where additional utility-scale wind capacity is developed in the REZ in the 2030s. The delay has a minimal impact on generation builds in the *Slower Growth* scenario.

Assessing the regrets associated with Waddamana to Palmerston transfer capability upgrade as an actionable project

**Table 56** presents the impact on weighted and worst weighted regrets of delaying the project to after its actionable window. While delaying the project increases regrets in *Step Change* and *Accelerated Transition*, it is the risk of over-investment in *Slower Growth* and associated reduction in regret when the project is delayed that ultimately drives a minor reduction in worst weighted regret of \$1 million.

**Table 56 Weighted and worst weighted regrets of CDP4 and CDP20 (\$ million) – Waddamana to Palmerston transfer capability upgrade**

	CDP4 – with actionable Waddamana to Palmerston transfer capability upgrade	CDP20– without actionable Waddamana to Palmerston transfer capability upgrade	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	423	-1
<i>Step Change</i>	2	29	27
<i>Accelerated Transition</i>	200	253	53
<b>Worst weighted regrets</b>	423	423	-1
<b>Ranking based on worst weighted regrets</b>	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.

### A6.5.4 Assessing projects that no longer deliver benefits at an actionable timing

#### Central Queensland to Southern Queensland Expansion

	Auburn River Switching Station	Queensland SuperGrid South
<b>EISD</b>	December 2031	December 2031
<b>Actionable window length</b>	2 years (not previously actionable)	4 years (actionable in the 2024 ISP)
<b>Cost</b>	\$67 million ( <i>Slower Growth, 2041-42</i> ) \$66 million ( <i>Step Change, 2034-35</i> ) \$67 million ( <i>Accelerated Transition, 2033-34</i> )	\$4,280 million ( <i>Slower Growth, 2041-42</i> ) \$4,185 million ( <i>Step Change, 2035-36</i> ) \$4,364 million ( <i>Accelerated Transition, 2034-35</i> )
<b>Flow path or REZ</b>	SQ-CQ	SQ-CQ
<b>Capacity increase</b>	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 consists of Queensland SuperGrid South, which is a new 500 kV line allowing for additional transfer capacity in both directions in the flow path between South 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. Similar to its treatment in the 2024 ISP, it requires the prior delivery of Gladstone Project.

A key benefit of Queensland SuperGrid South in the 2024 ISP was providing access to Borumba Pumped Hydro. However, delivery of Borumba Pumped Hydro is now delayed from 2031-32 to 2034-35, which reduces the benefits of delivering Queensland SuperGrid South at an actionable timing compared with the 2024 ISP.

#### Assessing the relative market benefits of Central Queensland to Southern Queensland Expansion via TOOT analysis

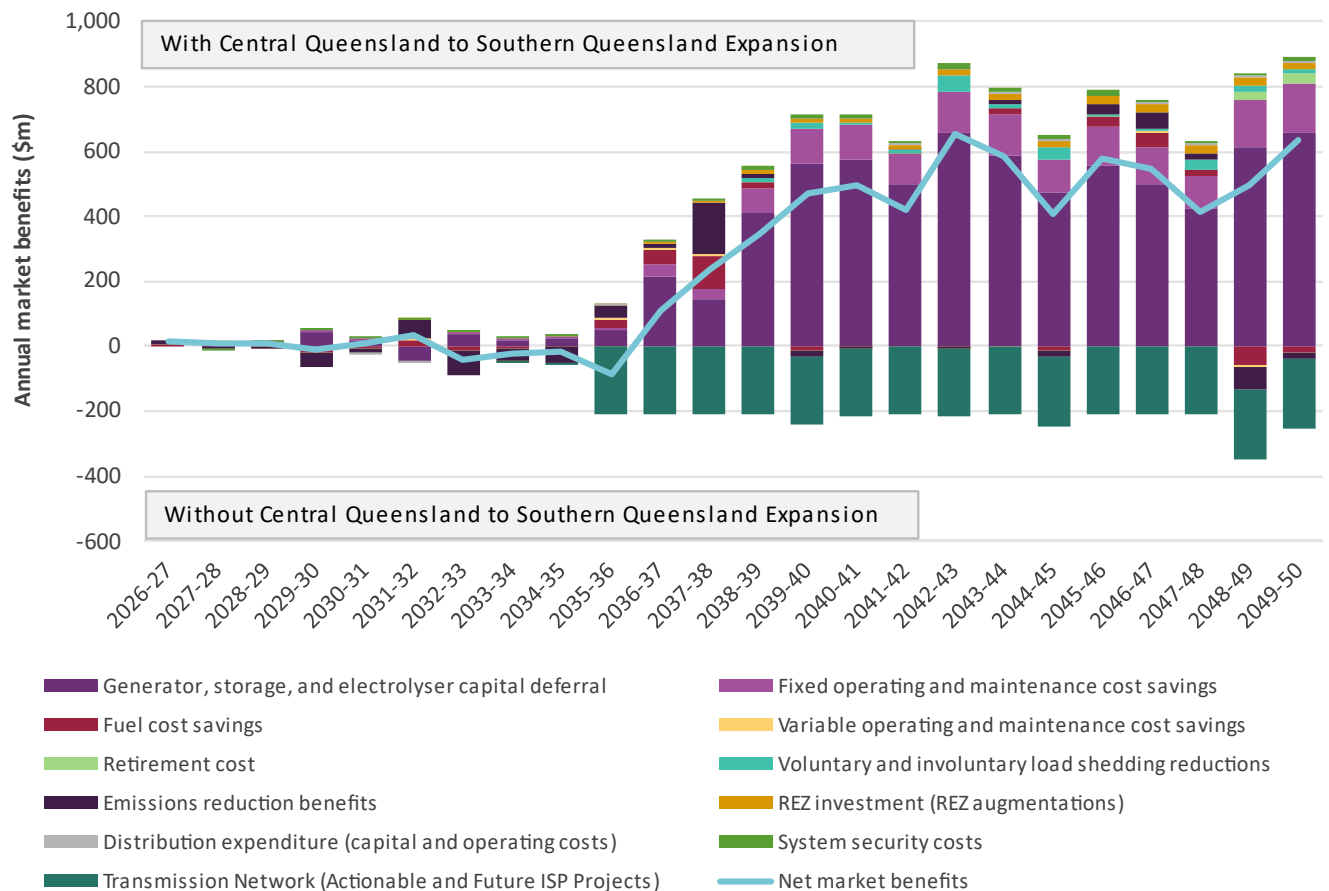
The benefits provided by Central Queensland to Southern Queensland Expansion in *Step Change* are presented, and the annual relative market benefits shown, in **Figure 39**. The projects, delivered across two stages, produce \$1,741 million in relative market benefits compared with not being delivered at any time in the outlook period. Benefits are primarily due to deferred capital costs of additional utility-scale storage in Queensland that would be needed without the improved access to Borumba Pumped Hydro that the augmentation provides from the late 2030s.

In *Step Change*, the project delays the need to build around 1.5 GW of utility-scale storage in Queensland by 2039-40 and reduce the need for additional renewable capacity in Queensland and New South Wales in later years as it improves the utilisation of southern Queensland capacity.

**Table 57 Relative market benefits of Central Queensland to Southern Queensland Expansion in Step Change**

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	2,030
Fixed operating and maintenance cost savings	411
Fuel cost savings	79
Variable operating and maintenance cost savings	4
Retirement cost	11
Voluntary and involuntary load shedding reductions	63
Emissions reduction benefits	3
REZ investment (REZ augmentations)	67
Distribution expenditure (capital and operating costs)	9
System security costs	47
<b>Gross market benefits</b>	<b>2,725</b>
Transmission Network (Actionable and Future ISP Projects)	-984
<b>Total net market benefits</b>	<b>1,741</b>

**Figure 39 Annual relative market benefits of Central Queensland to Southern Queensland Expansion in Step Change (at 2035-36)**



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

As **Table 58** highlights, not actioning this project results in an increase in net market benefits in both *Step Change* and *Slower Growth* (\$229 million and \$154 million, respectively). Only in *Accelerated Transition* does the project deliver relative net market benefits at an actionable timing, as the delay decreases the benefits by \$186 million. Therefore, Central Queensland to Southern Queensland Expansion has been identified as a future ISP project rather than an actionable project in this Draft 2026 ISP.

**Table 58 Comparing net market benefits between CDP8 and CDP4 (\$ billion) – Central Queensland to Southern Queensland Expansion**

	CDP8 – with actionable Central Queensland to Southern Queensland Expansion	CDP4 – without actionable Central Queensland to Southern Queensland Expansion	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.48	12.64	0.15
<i>Step Change</i>	25.25	25.48	0.23
<i>Accelerated Transition</i>	33.76	33.57	-0.19
<b>Weighted net market benefits</b>	24.10	24.20	0.10
<b>Ranking weighted net market benefits</b>	8	1	N/A

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 project delivers limited generator and storage capital expenditure benefits by delaying the need for additional wind capacity in North and Central Queensland. The project provides access to coal generation in Central Queensland, and to Borumba Pumped Hydro once the project is developed in 2034-35.

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 Borumba Pumped Hydro coupled with utility-scale solar in North and South Queensland displace coal generation in Queensland and New South Wales.

In *Accelerated Transition*, the project delivers net market benefits by facilitating greater use of Borumba Pumped Hydro to avoid the need for additional utility-scale storage and utility-scale solar capacity in Queensland, as well as reduced fuel costs.

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

**Table 59** presents the weighted and worst weighted regrets of both CDPs. Delivering the project at an actionable timing decreases regrets only in *Accelerated Transition*.

**Table 59 Weighted and worst weighted regret of CDP8 and CDP4 (\$ million) – Central Queensland to Southern Queensland Expansion**

	CDP8 – with actionable Central Queensland to Southern Queensland Expansion	CDP4 – without actionable Central Queensland to Southern Queensland Expansion	Change in weighted regrets associated with non-actionable delivery of the projects <sup>A</sup>
<i>Slower Growth</i>	465	423	-42
<i>Step Change</i>	107	2	-105
<i>Accelerated Transition</i>	150	200	50
<b>Worst weighted regrets</b>	465	423	-42
<b>Ranking based on worst weighted regrets</b>	9	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.

### A6.5.5 Projects subject to ongoing analysis

AEMO considers that the following list of projects require further analysis to ascertain their benefits and will continue their assessment following the publication of the Draft 2026 ISP in preparing the 2026 ISP.

#### Queensland – New South Wales Interconnector (QNI) Connect

<b>EISD</b>	March 2034
<b>Actionable window length</b>	4 years (actionable in 2024 ISP)
<b>Cost</b>	\$3,283 million ( <i>Slower Growth</i> , 2033-34) \$3,323 million ( <i>Step Change</i> , 2033-34) \$3,421 million ( <i>Accelerated Transition</i> , 2033-34)
<b>Flow path or REZ</b>	NNSW-SQ
<b>Capacity increase</b>	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.

QNI Connect would improve sharing of firming capacity between Queensland and southern regions, including the deep storage Borumba Pumped Hydro project, particularly as coal generators retire. In improving the capacity to share energy between regions, delivering the augmentation reduces the development need for wind and storage capacity across Queensland, New South Wales and Victoria.

Given the recent release of the Queensland Energy Roadmap<sup>37</sup>, and its influence on Queensland electricity planning, this project is categorised as requiring further analysis and stakeholder engagement for the 2026 ISP following publication of the Draft 2026 ISP.

<sup>37</sup> See <https://www.treasury.qld.gov.au/files/Queensland-Energy-Roadmap-2025-25-043.pdf>.

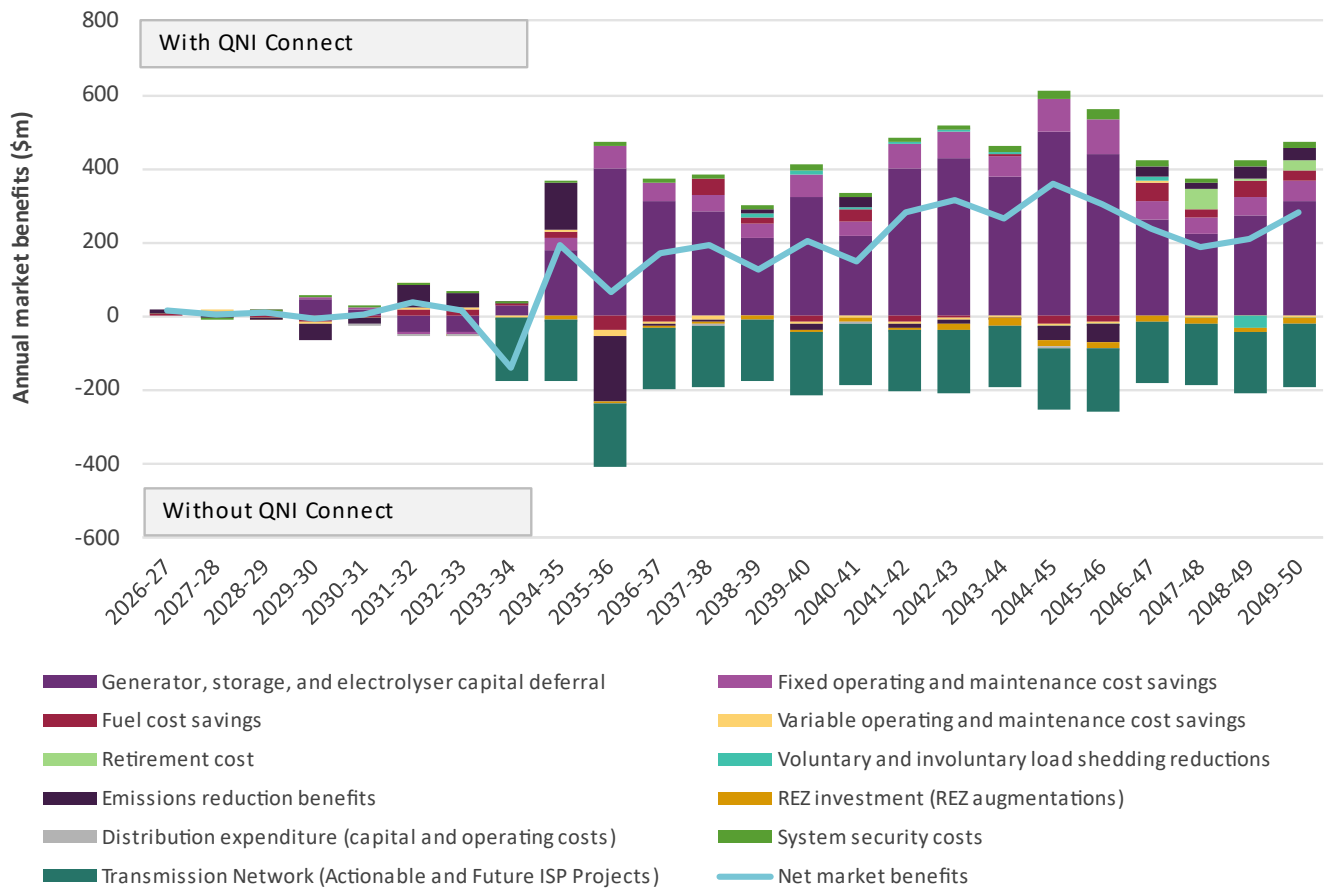
Assessing the relative market benefits of QNI Connect via TOOT analysis

The benefits associated with QNI Connect in *Step Change* are presented in **Table 60** and **Figure 40**. The main sources of relative market benefits are avoided generator and storage capital costs, fuel cost savings, and fixed operating and maintenance cost savings. Based on the current assumptions, the augmentation delivers around \$1.06 billion in relative market benefits.

**Table 60** Relative market benefits of QNI Connect in *Step Change*

Class of market benefit	Relative market benefit (NPV, \$ million)
Generator and storage capital deferral	1,644
Fixed operating and maintenance cost savings	283
Fuel cost savings	54
Variable operating and maintenance cost savings	-19
Retirement cost	18
Voluntary and involuntary load shedding reductions	10
Emissions reduction benefits	0
REZ investment (REZ augmentations)	-63
Distribution expenditure (capital and operating costs)	-2
System security costs	79
<b>Gross market benefits</b>	<b>2,004</b>
Transmission Network (Actionable and Future ISP Projects)	-952
<b>Total net market benefits</b>	<b>1,052</b>

**Figure 40 Annual relative market benefits of QNI Connect in Step Change (2033-34)**



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

Table 61 presents the net market benefits associated with delivering QNI Connect as an actionable project by comparing CDP4 and CDP17 (which is similar to CDP4 but features the project’s delivery beyond the actionable window). Development of an actionable QNI Connect requires development of the New England REZ Network Infrastructure Project. As such, both CDPs keep the latter project fixed at an actionable timing.

Continuing to progress QNI Connect as actionable increases net market benefits in Step Change and Accelerated Transition by around \$671 million and \$208 million respectively, relative to the benefits accrued if the project were delivered as a future project. In Slower Growth however, delaying the project would increase net market benefits by \$502 million. Overall, weighting all three scenarios and based on current assumptions, the benefits in Step Change and Accelerated Transition that are associated with a delivery at an actionable timing result in weighted net market benefits of around \$253 million at an actionable timing.

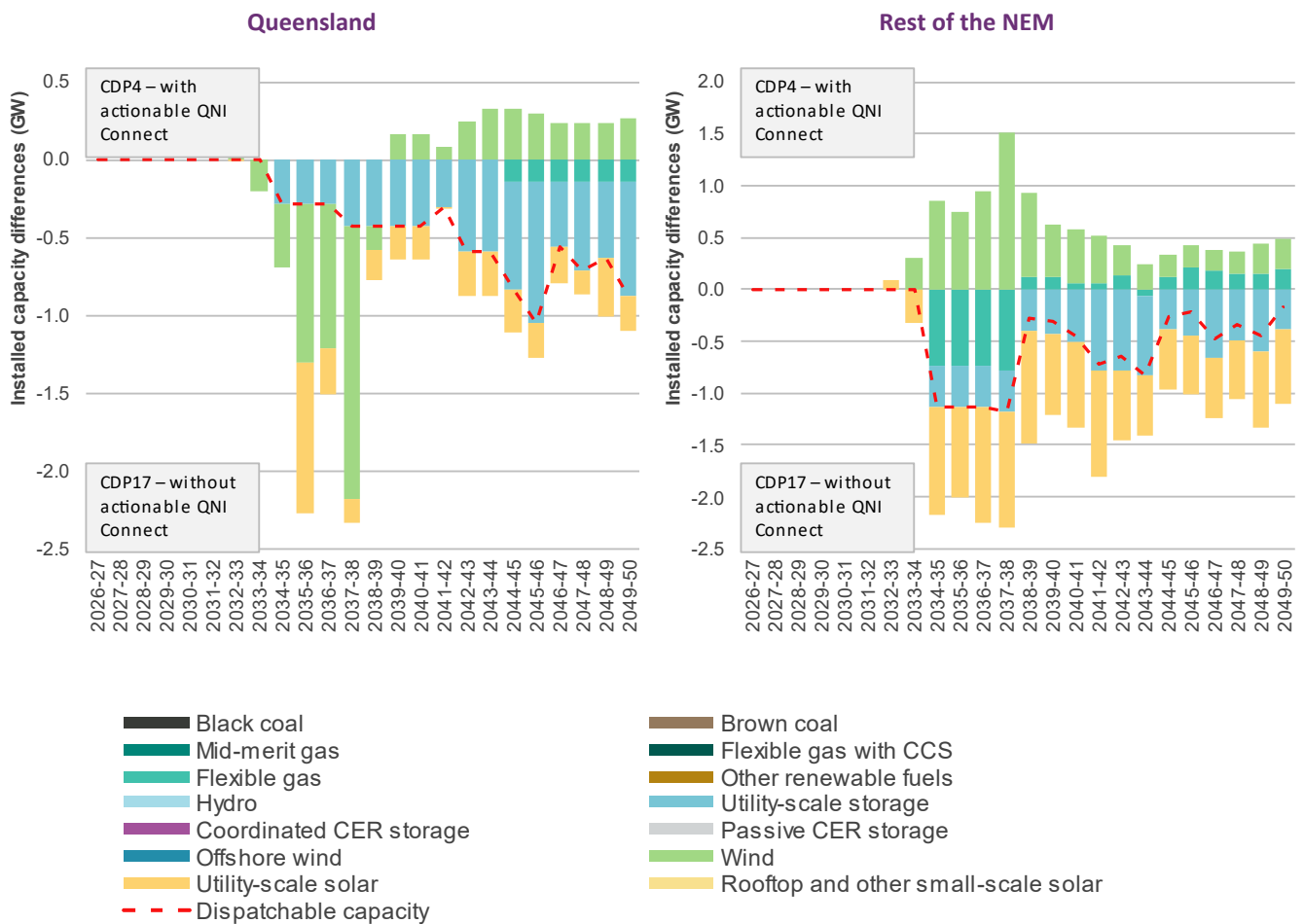
**Table 61 Comparing net market benefits between CDP4 and CDP17 (\$ billion) – QNI Connect**

	CDP4 – with actionable QNI Connect	CDP17 – without actionable QNI Connect	Change in net market benefits associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	12.64	13.14	0.50
<i>Step Change</i>	25.48	24.81	-0.67
<i>Accelerated Transition</i>	33.57	33.27	-0.30
<b>Weighted net market benefits</b>	24.20	23.94	-0.25
<b>Ranking weighted net market benefits</b>	1	14	N/A

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*, as shown in **Figure 41**, the benefits of an actionable QNI Connect stem from deferring nearly 1.8 GW of utility-scale solar capacity as well as 400 MW of additional utility-scale storage capacity in Queensland and New South Wales. An actionable QNI Connect results in further development of higher resource wind sites in New South Wales. It also enables remaining coal capacity in Queensland and other developments to provide support to the rest of the NEM, particularly Victoria, which otherwise builds around 1 GW of flexible gas and utility-scale storage in 2034-35 to firm and back up renewables.

**Figure 41 Capacity differences delayed (top) versus actionable (bottom) in Step Change – QNI Connect**



Assessing the regrets associated with QNI Connect as a non-actionable project

**Table 62** below presents the weighted and worst weighted regrets associated with this augmentation option across the scenarios. Delaying the project would lead to weighted regret in *Step Change* (approximately \$311 million) on account of the higher benefits that the project delivers in that scenario.

**Table 62 Weighted and worst weighted regret of CDP4 and CDP17 (\$ million) – QNI Connect**

	CDP4 – with actionable QNI Connect	CDP14 – without actionable QNI Connect	Change in weighted regrets associated with non-actionable delivery of the project <sup>A</sup>
<i>Slower Growth</i>	423	288	-135
<i>Step Change</i>	2	311	309
<i>Accelerated Transition</i>	200	280	80
<b>Worst weighted regrets</b>	423	311	-112
<b>Ranking based on worst weighted regrets</b>	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.

While QNI Connect is actionable in the proposed ODP, the Queensland Energy Roadmap and strong policy-driven development of generation and storage in both Queensland and New South Wales may impact the benefits of greater resource sharing between the two states. Before the final 2026 ISP, AEMO will engage with stakeholders and conduct sensitivity analyses to reduce the uncertainty around material assumptions for this investment.

New England REZ Network Infrastructure project is a pre-requisite for QNI Connect and their inter-dependencies will be further considered as part of this analysis. Ultimately, the New England REZ Network Infrastructure project would progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

### Northern Transmission Project

<b>EISD</b>	July 2029
<b>Actionable window length</b>	4 years (actionable in the 2024 ISP)
<b>Cost</b>	\$655 million ( <i>Slower Growth</i> , 2029-30) \$659 million ( <i>Step Change</i> , 2029-30) \$666 million ( <i>Accelerated Transition</i> , 2029-30)
<b>Flow path or REZ</b>	MN1 group constraint, facilitating power out of mid-north SA
<b>Capacity increase</b>	1200 MW

In the 2024 ISP, AEMO identified that a transmission augmentation to support network capacity upgrades in the mid-north of South Australia, supporting flows south to Adelaide and/or north to Port Augusta and the Eyre Peninsula, was an actionable ISP project. In commencing the RIT-T for the Mid North South Australia REZ expansion project, ElectraNet has identified options in addition to those assessed in 2024.

The Northern Transmission Project (formerly Mid North South Australia REZ project) is a new 275 kV augmentation focused on supporting load development in northern South Australia, by increasing network capacity out of mid-north South Australia REZs by 1,200 MW and costing \$659 million if delivered at its EISD of 2029-2030. Since the Mid North South Australia REZ expansion project was found actionable in the 2024 ISP, it (including all its alternative variants) has a four-year actionable window in this ISP.

### Assessing the relative and market benefits of Northern Transmission Project

While this project has not been found to deliver positive net market benefits across the scenario collection, AEMO considers that the project could deliver increased benefits if generation and storage cannot, or does not, connect in areas considered optimal in ISP modelling for this Draft 2026 ISP.

Further examination of firming developments expected in South Australia, and the availability of gas for flexible gas generation, is needed. Therefore, the project requires further analysis and stakeholder engagement for the 2026 ISP, following publication of the Draft 2026 ISP, to ascertain whether it would provide optimal benefit to consumers as previously identified in the 2024 ISP.

### A6.5.6 Summarising the benefits of a coordinated approach to transmission development

**Table 63** presents a comparison of the weighted net market benefits from: CDP2 which is based on the least-cost DP under *Step Change*; CDP4 which has the highest weighted net market benefits; and CDP23 which has no projects delivered within their actionable windows.

**Table 63 Determining the benefits of a coordinated approach to transmission development (\$ billion)**

CDP	<i>Slower Growth</i>	<i>Step Change</i>	<i>Accelerated Transition</i>	Weighted net market benefits
<b>CDP2: Least-cost <i>Step Change</i></b>	12.64	25.48	33.43	24.16
<b>CDP4: Highest weighted net market benefit</b>	12.64	25.48	33.57	24.20
<b>CDP23: No actionable projects</b>	11.61	21.54	20.77	18.65
<b>Net market benefits of CDP4 due to actionability of projects</b>	1.03	3.93	12.80	5.54

The weighted net market benefits arising from delivering the collection of actionable transmission projects at EISD is \$5.54 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<sup>38</sup>), with the increase due to several reasons, including:

- 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 removal of projects that are now committed or anticipated,
- 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,
- increases in the capital and operating costs for generation projects, including projects deferred (as discussed in the 2025 IASR), and
- Is significant capacity (including dispatchable capacity) being added to the system since the 2024 ISP, which – given their status as existing, anticipated and committed projects – is not costed.

<sup>38</sup> Adjusted using a 5.7% CPI assumption consistent with the 2025 IASR.



## A6.6 Step 5a: Selecting the proposed optimal development path

This section summarises the insights from Section A6.5 and explains the reasoning that underpins the determination of the ODP. The resilience of the selected ODP to sensitivities is discussed in Section A6.7. Section A6.8 discusses the overall influence of the findings from the sensitivity analysis to the ODP selection and presents the ODP.

**Table 64** shows the differences in transmission augmentations between these CDPs, and **Table 65** presents the top 10 CDPs with the highest weighted net market benefits.

**Table 64 Potential actionable projects in the top-ranked CDPs by weighted net market benefits**

CDP	Gladstone Project	Central Queensland to Southern Queensland Expansion	QNI Connect	New England REZ Network Infrastructure Project (REZ)	New England REZ Network Infrastructure Project (Flow path)	Dubbo Distribution Project <sup>A</sup>	Sydney Ring North (Hunter Transmission Project 1.0)	Sydney Ring South power flow controller option	Sydney Ring South – 500kV option (Stage 1)	Sydney Ring South – 500kV option (Stage 2)	Northern Transmission Project	Switching Station Near Wondalga	Victoria – New South Wales Interconnector West (VNI)	Western Victoria Reinforcement program	Eastern Victoria Reinforcement program (Option 1)	Eastern Victoria Reinforcement program (Option 2)	Gippsland Offshore Wind Transmission Stage 1	Gippsland Offshore Wind Transmission Stage 2 (Phase 1)	Gippsland Offshore Wind Transmission Stage 2 (Phase 2)	Project Marinus Stage 2	Waddamana to Palmerston transfer capacity upgrade
CDP4	✓		✓	✓	✓		✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP6	✓		✓	✓	✓		✓	✓	✓	✓		✓	✓	✓			✓	✓	✓	✓	✓
CDP16	✓						✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP10	✓		✓	✓	✓		✓	✓				✓	✓	✓		✓	✓	✓	✓	✓	✓
CDP2	✓		✓	✓	✓		✓	✓					✓	✓			✓	✓	✓	✓	✓
CDP20	✓		✓	✓	✓		✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP9	✓		✓	✓	✓		✓	✓				✓	✓	✓	✓		✓	✓	✓	✓	✓
CDP8	✓	✓	✓	✓	✓		✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP7	✓		✓	✓	✓	✓	✓	✓				✓	✓	✓			✓	✓	✓	✓	✓
CDP15	✓		✓	✓	✓		✓	✓				✓	✓				✓	✓	✓	✓	✓

A: The ISP framework does not apply to this project, however, this could go through the normal Regulatory Investment Test for Distribution.

**Table 65 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	WNMB Rank	Worst weighted regrets	WWR Rank
4	ODP (Least-cost DP in <i>Step Change</i> scenario with actionable Switching Station Near Wondalga)	12.64	25.48	33.57	24.20	1	0.42	6
6	ODP with Sydney Ring South – 500 kV option	12.42	25.35	33.94	24.18	2	0.48	13
16	ODP without New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI)	14.18	24.95	32.84	24.17	3	0.40	2
10	ODP with Eastern Victoria Reinforcement program (Option 2)	12.57	25.46	33.55	24.16	4	0.44	9
2	Least-cost DP in <i>Step Change</i> scenario	12.64	25.48	33.43	24.16	5	0.42	4
20	ODP without Waddamana to Palmerston transfer capacity upgrade	12.64	25.42	33.37	24.12	6	0.42	5
9	ODP with Eastern Victoria Reinforcement program (Option 1)	12.45	25.42	33.55	24.11	7	0.47	11
8	ODP with Central Queensland to Southern Queensland Expansion	12.48	25.25	33.76	24.10	8	0.46	10
7	ODP with Dubbo Distribution Project	12.42	25.45	33.45	24.09	9	0.48	14
15	ODP without Western Victoria Reinforcement program	12.63	25.36	33.30	24.07	10	0.42	7

The difference between the first- and fifth-ranked CDPs on a weighted net market benefits is just \$34 million, largely due to having very similar combinations of projects with timing varying no more than four years of each other. The selection of the ODP therefore 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, their worst weighted regrets, and the driver of their benefits and regrets.

CDP4 provides the highest weighted net market benefits from the CDP collection. The projects in CDP4 that are actionable collectively provide significant benefits across scenarios, support the decarbonisation of the NEM, and allow for the efficient sharing of VRE across the NEM. CDP4 also perform relatively well in each scenario which suggests that it has a good balance of benefits across all the scenarios and is robust to alternate future world views.

Notably, CDP4 also delivers the highest net market benefits in *Step Change* equal with the least cost DP for *Step Change* (CDP2). CDP4 delivers the sixth-highest net market benefits in *Slower Growth*, ranking only behind the CDPs that exclude actioning the stages of the New England REZ Network Infrastructure Project and QNI Connect (which is flagged for further analysis in this proposed ODP), and the Waddamana to Palmerston transfer capability upgrade. In *Accelerated Transition*,

CDP4 also performs well compared with the majority of the top 10 CDPs, ranking fourth overall. It ranks below CDP6 and CDP8, which feature the actionable delivery of the 500 kV option (Stages 1 and 2) to Sydney Ring South and Central Queensland to Southern Queensland Expansion projects respectively.

CDP4 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. Over-investment risk is flagged as the potential worst weighted regret for most CDPs, which is expected given that industrial load retirements can have a relatively large impact on the need for generation, storage and network developments, compared with adapting the preferred location and type of capacity considering the availability of network developments.

CDP6 is the second highest WNMB ranking CDP but to rank higher than CDP, but to rank higher than CDP4, the relative weighting of *Slow Growth* scenario would need to decrease to 21%, and *Accelerated Transition* would need to increase to 33%. Moreover, CDP6 is less robust to the different scenarios that may play out in future, compared to CDP4.

**Based on the assessment of the relative merits of each CDP, AEMO considers CDP4 to be the best candidate and proposes it as the 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. This selection of CDP4 to be the proposed ODP is further confirmed by the assessment of the CDPs under different sensitivities, discussed in the following sub-sections.**

## A6.7 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 proposed ODP. The sensitivity analysis in this section is focused on sensitivities to the *Step Change* scenario.

The impact of these sensitivities on generation and storage capacity development is explored in Appendix A2. The capacity developments, cost-benefit and emissions outcomes are also provided in the **Generation and Storage Outlook Workbooks**.

The sensitivities explored in the Draft 2026 ISP focus on the impact on the ODP 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,
- assumed coal-fired generation capacity shutdown timings in the *Step Change* scenario were to occur faster or slower than anticipated,
- alternative gas development pathways (GDPs) impact the availability of gas as a fuel in each scenario,
- the level of CER coordination is to align with *Accelerated Transition's* or, alternatively, remain at 2024-25 levels, and
- energy efficiency improvements were to slow down compared with what was assumed in the *Step Change* scenario.

### A6.7.1 Constrained Delivery

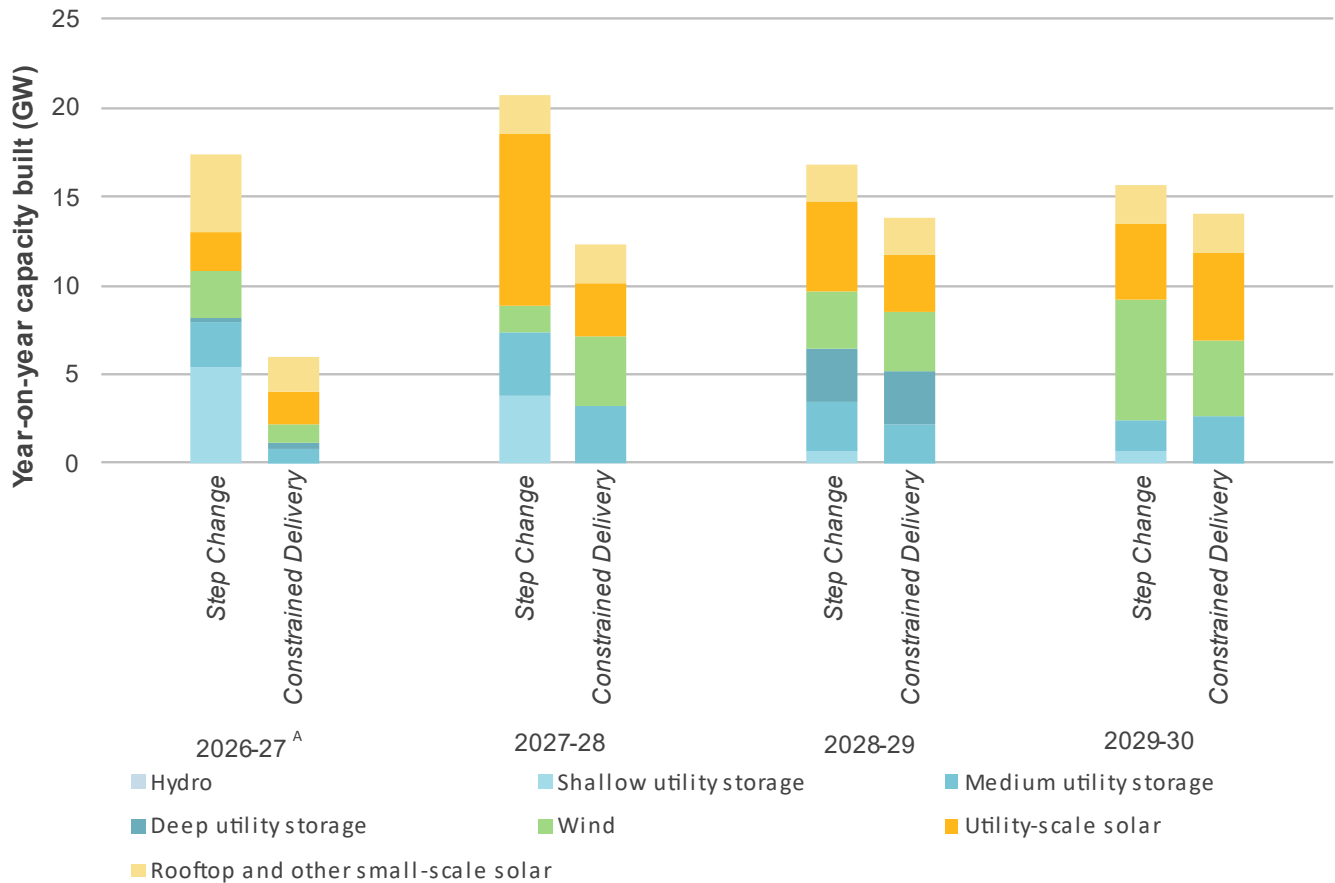
AEMO has explored a *Constrained Delivery* sensitivity analysis to see whether the transmission projects proposed in the ODP would still deliver material benefits to consumers if transmission as well as generation and storage projects were unable to be delivered at the pace required. There may be many 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.

A summary of key assumption changes in this sensitivity are as follows:

- NEM-wide annual build limits are imposed on future wind, utility-scale solar, and utility-scale storages until 2034-35. The delivery of committed and anticipated projects as well as other new entrant projects are assumed to be impacted by the same limitations. The limit has been calculated considering the trends in pace of connection of individual technologies observed over the past five years, and its impacts are presented in **Figure 42** 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.
- Offshore wind projects are also impacted by the development constraints delaying the delivery of 9 GW of capacity by three years.
- The cost of generation, storage and transmission was also assumed to rise 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 2024-25 GenCost report. 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 NEM renewable annual build capacities, Step Change versus Constrained Delivery sensitivity, 2026-27 to 2029-30 (GW)**



Note: the values for 2026-27 are presenting the capacity growth compared to 2024-25 installed capacity. All other years present the year-on-year growth.

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 proposed ODP in the *Constrained Delivery* sensitivity are presented in **Table 66**, alongside the primary assumptions of *Step Change*. The constraints that affect infrastructure delivery reduce the weighted net market benefits by approximately \$8.3 billion, however the benefit is still clearly positive to consumers even if conditions limit the pace of commissioning the generation, storage, and transmission developments of the proposed ODP.

In these circumstances, the achievement of various policies – such as renewable energy development or emissions reduction objectives – may be missed but would catch up soon after. For example, with these limitations applied, the renewable energy share is only 75% by 2030, lower than the Powering Australia Plan target of 82% renewable share by 2030. With less renewable energy development, the NEM’s contribution to the 2030 emissions reduction target is also lower than the scenarios, exceeding the NEM’s allocated share of the target by 5.5 Mt CO<sub>2</sub>-e. Over the horizon, slower developments affect the ‘no transmission’ counterfactual more than the scenario assumptions, leading to more coal

generation in the earlier years of the outlook period and a relative increase in emissions reduction benefits of the proposed ODP compared to the scenario’s assumptions.

**Table 66 Comparison of net market benefits delivered by CDP4 in Step Change and in the Constrained Delivery sensitivity (\$ million)**

Class of market benefit	Constrained Delivery sensitivity	Core assumptions	Difference
Generator, storage, and electrolyser capital deferral	10,814	18,994	-8,180
Fixed operating and maintenance cost savings	4,216	3,344	872
Fuel cost savings	9,963	13,234	-3,271
Variable operating and maintenance cost savings	817	781	36
Retirement cost	52	177	-125
Voluntary and involuntary load shedding reductions	-135	-102	-33
Emissions reduction benefits	2,806	78	2,727
REZ investment (REZ augmentations)	-1,162	-756	-406
Distribution expenditure (capital and operating costs)	33	59	-25
System security costs	-24	156	-181
<b>Gross market benefits</b>	<b>27,379</b>	<b>35,965</b>	<b>-8,586</b>
Transmission Network (Actionable and Future ISP Projects)	-10,176	-10,486	310
<b>Total market benefits</b>	<b>17,203</b>	<b>25,479</b>	<b>-8,276</b>

**Table 67** presents the net market benefits and rankings of key CDPs in the *Constrained Delivery* sensitivity alongside *Step Change*. Limitations on the delivery of generation and storage capacity and longer lead times for transmission mean there is greater value in delivering the benefits of stronger network connections across the NEM as early as possible in the *Constrained Delivery* sensitivity. This is evident in the generally improved performance of CDPs which feature more actionable projects.

For example, CDP3, which is based on the least-cost DP for *Accelerated Transition*, features the most projects with actionable timings in the CDP collection and improves from a relative ranking of 12<sup>th</sup> under the scenario’s assumptions (from the selected CDPs tested) to become the best-performing 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<sup>39</sup>.

As a second example, the Sydney Ring South 500 kV option also has greater relative benefits if delivered at an actionable timing under this sensitivity. Comparing the difference between CDP6 and CDP4 shows that the relative benefits for actioning the project improve from -\$21 million under core assumptions (that is, a non-actionable timing is preferred) to \$322 million if there were constraints on infrastructure delivery.

On the other hand, CDPs which feature fewer actionable projects than CDP4, such as CDP16, CDP20, and CDP15, perform relatively worse in the *Constrained Delivery* sensitivity. This demonstrates the robustness of the ODP and that there is still substantial value in progressing with at least the projects identified as actionable in CDP4 (the proposed ODP) if delivery constraints were to materialise. Commencing or continuing work on these projects is an important mitigant for the risk of delays.

<sup>39</sup> That is, if the assumptions for *Accelerated Transition* and *Slower Growth* were unchanged, and the delivery limitations affect only the *Step Change* scenario.

**Table 67 Net market benefits and weighted net market benefits for key CDPs (in \$ billion), Constrained Delivery sensitivity and core assumptions**

CDP	Description	Constrained Delivery sensitivity			Core assumptions		
		Step Change	WNMB	WNMB rank	Step Change	WNMB	WNMB rank
CDP3	Least-cost DP for <i>Accelerated Transition</i>	17.85	20.74	1	24.84	23.96	12
CDP6	CDP4 with actionable Sydney Ring South 500kV upgrade	17.82	20.71	2	25.35	24.18	2
CDP2	Least-cost DP for <i>Step Change</i>	17.39	20.44	3	25.48	24.16	4
CDP10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	17.35	20.43	4	25.46	24.16	4
CDP9	CDP4 with actionable Eastern Victoria Reinforcement program (Option 1)	17.38	20.42	5	25.42	24.11	7
CDP4	CDP2 with actionable Switching Station Near Wondalga	17.20	20.39	6	25.48	24.20	1
CDP16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	16.65	20.35	7	24.95	24.17	3
CDP7	CDP4 with actionable Dubbo Distribution Project	17.31	20.35	8	25.45	24.09	8
CDP20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	17.20	20.34	9	25.42	24.12	6
CDP15	CDP4 without actionable Western Victoria Reinforcement program	17.22	20.32	10	25.36	24.07	9
CDP13	CDP4 without actionable Sydney Ring North (Hunter Transmission Project 1.0)	17.16	20.26	11	25.41	24.05	10
CDP11	CDP4 with actionable Northern Transmission Project	17.22	20.24	12	25.31	23.96	11
CDP21	CDP4 without actionable Project Marinus Stage 2	16.78	19.71	13	25.38	23.67	13

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

## A6.7.2 Coal retirements

The retirement sequence of coal-fired generation capacity in the ISP is a least-cost path to meet NEM-wide emissions targets and other relevant, eligible government policy, while maintaining minimum levels of energy generation output for each coal generator and meeting any announced closure dates. The approach that AEMO takes in determining the coal retirement schedule is detailed in the *ISP Methodology*<sup>40</sup>.

In these sensitivities, AEMO assumed higher and lower levels of minimum annual energy generation requirements for coal, effectively enabling less or more flexibility for coal generators. Lower minimum energy generation requirements represents a future with coal generators configured to operate more flexibly, potentially through seasonal operation or two-shifting (typically operating overnight and into the morning, switching off during the peak solar-generation midday period, and returning to support the evening peak), while higher energy generation requirements represent less operational flexibility for generators.

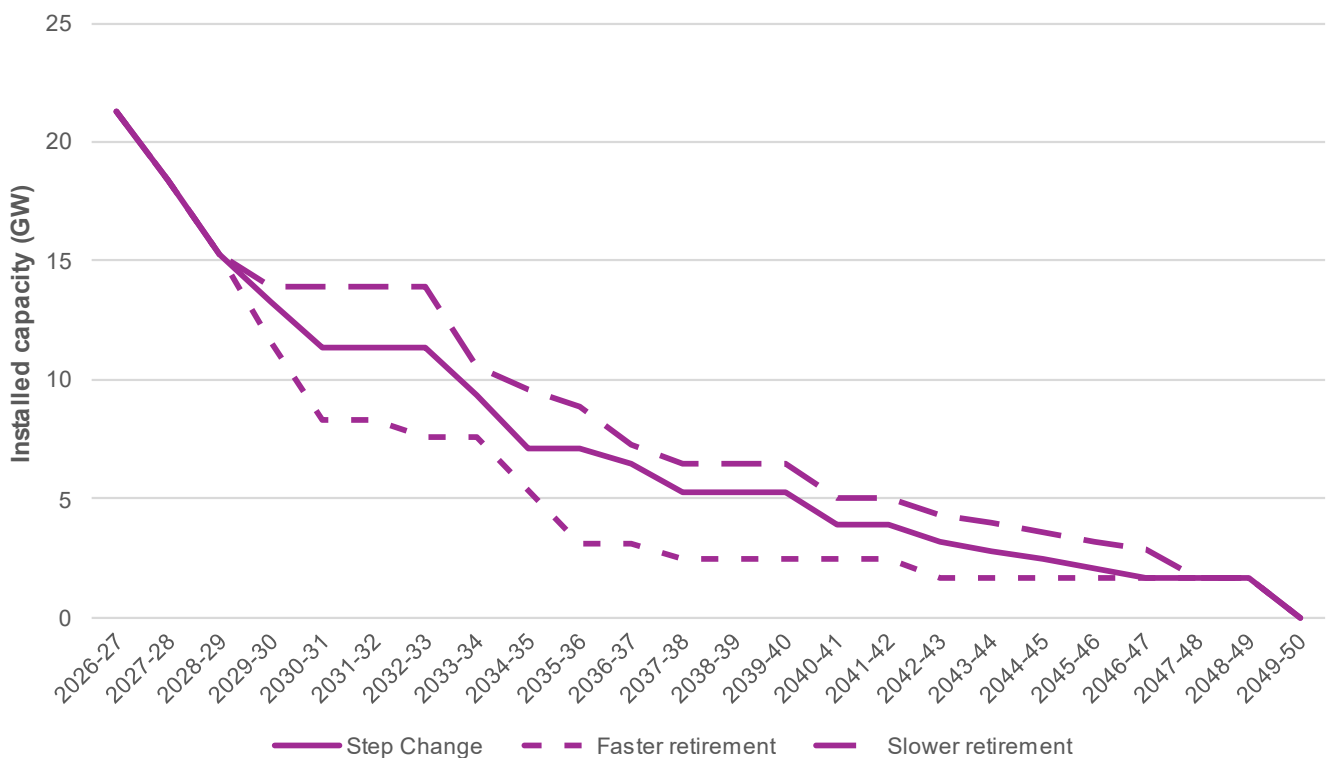
<sup>40</sup> At [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?la=en](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?la=en).

Two sensitivities have been analysed:

- The *Slower Coal Retirement* sensitivity focused on increasing generator operational flexibility, to enable longer participation in the market at lower operating volumes.
- In contrast, the *Faster Coal Retirement* sensitivity explored if coal plants need to run at higher levels, which may lead to faster closures with increasing competition from renewable resources. Faster closures typically increase the urgency to develop replacement firming capacity across the NEM, while slower retirements and more flexible coal operation may slow the need to develop firming capacity to replace coal generation.

The impact of these changes on coal-fired generation capacity compared to the core scenario are shown in **Figure 43**. The impacts on ISP development opportunities are discussed in Appendix A2.

**Figure 43 NEM black and brown coal-fired generation Step Change, Faster Coal Retirement and Slower Coal Retirement sensitivity**



### Faster Coal Retirements

The comparison of net market benefits delivered by the ODP between the *Faster Coal Retirement* sensitivity and the *Step Change* scenario (as seen in **Table 68**) reveals a \$6 billion increase in the benefits of transmission development if coal were to close earlier. Flexible gas generation, utility-scale storage and wind farms in existing REZs with available capacity are required to be developed much earlier to meet energy consumption with fewer coal units available.

**Table 68 Comparison of net market benefits delivered by CDP4 in Step Change – Faster Coal Retirement sensitivity versus core assumptions (\$ million)**

Class of market benefit	Faster Coal Retirement sensitivity	Core assumptions	Difference
Generator, storage, and electrolyser capital deferral	25,227	18,994	6,232
Fixed operating and maintenance cost savings	3,513	3,344	170
Fuel cost savings	12,782	13,234	-452
Variable operating and maintenance cost savings	923	781	142
Retirement cost	-10	177	-186
Voluntary and involuntary load shedding reductions	-22	-102	79
Emissions reduction benefits	290	78	212
REZ investment (REZ augmentations)	-871	-756	-115
Distribution expenditure (capital and operating costs)	70	59	12
System security costs	69	156	-87
<b>Gross market benefits</b>	<b>41,970</b>	<b>35,965</b>	<b>6,006</b>
Transmission Network (Actionable and Future ISP Projects)	-10,486	-10,486	0
<b>Total market benefits</b>	<b>31,485</b>	<b>25,479</b>	<b>6,006</b>

Shown in **Table 69**, the proposed ODP consistently remains one of the strongest performers on a weighted net market benefit basis – reinforcing its resilience to the change in assumptions. In contrast, CDPs that do not action VNI West or Sydney Ring transmission upgrades (CDP22 and CDP12) perform relatively poorly, which shows that once coal retires these interconnections are critical for enabling flows into the MEL and the SNW sub-regions which have limited potential for utility-scale generation development.

**Table 69 Net market benefits and weighted net market benefits for key CDPs (in \$ billion), *Faster Coal Retirement* sensitivity and core assumptions**

CDP	Description	<i>Faster Coal Retirement</i> sensitivity			Core assumptions		
		<i>Step Change</i>	WNMB	WNMB rank	<i>Step Change</i>	WNMB	WNMB rank
<b>CDP4</b>	CDP2 with actionable Switching Station Near Wondalga	31.48	26.96	1	25.48	24.20	1
<b>CDP16</b>	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	31.01	26.96	2	24.95	24.17	3
<b>CDP6</b>	CDP4 with actionable Sydney Ring South 500kV upgrade	31.36	26.94	3	25.35	24.18	2
<b>CDP2</b>	Least-cost DP for <i>Step Change</i>	31.50	26.93	4	25.48	24.16	5
<b>CDP10</b>	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	31.46	26.92	5	25.46	24.16	4
<b>CDP20</b>	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	31.45	26.89	6	25.42	24.12	6
<b>CDP7</b>	CDP4 with actionable Dubbo Distribution Project	31.44	26.85	7	25.45	24.09	7
<b>CDP13</b>	CDP4 without actionable Sydney Ring North (Hunter Transmission Project 1.0)	31.29	26.76	8	25.41	24.05	8
<b>CDP17</b>	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	30.91	26.75	9	24.81	23.94	10
<b>CDP11</b>	CDP4 with actionable Northern Transmission Project	31.26	26.70	10	25.31	23.96	9
<b>CDP21</b>	CDP4 without actionable Project Marinus Stage 2	31.19	26.34	11	25.38	23.67	11
<b>CDP22</b>	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	30.86	25.99	12	25.28	23.43	12
<b>CDP12</b>	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	29.75	24.87	13	24.34	22.39	13

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

### Slower Coal Retirements

Under the *Slower Coal Retirements* sensitivity, the proposed ODP delivers a net market benefit that is higher by \$2.78 billion compared with that found in *Step Change*, driven by a reduced need to build utility-scale capacity in the 2040s as coal is available to dispatch in the NEM and provide firm capacity for longer. This highlights the market value of modifying plant to enable more flexible operation.

**Table 70 Comparison of net market benefits delivered by CDP4 in Step Change – Slower Coal Retirement sensitivity versus core assumptions (\$ million)**

Class of market benefit	Slower Coal Retirement Sensitivity	Core assumptions	Difference
Generator, storage, and electrolyser capital deferral	22,607	18,994	3,613
Fixed operating and maintenance cost savings	3,979	3,344	635
Fuel cost savings	11,554	13,234	-1,680
Variable operating and maintenance cost savings	751	781	-30
Retirement cost	-2	177	-178
Voluntary and involuntary load shedding reductions	43	-102	145
Emissions reduction benefits	16	78	-62
REZ investment (REZ augmentations)	-525	-756	231
Distribution expenditure (capital and operating costs)	67	59	8
System security costs	251	156	95
<b>Gross market benefits</b>	<b>38,742</b>	<b>35,965</b>	<b>2,777</b>
Transmission Network (Actionable and Future ISP Projects)	-10,486	-10,486	0
<b>Total market benefits</b>	<b>28,256</b>	<b>25,479</b>	<b>2,777</b>

**Table 71** demonstrates the resilience of CDP4 (the proposed ODP) to the *Slower Coal Retirement* assumptions – delivering the second-highest weighted net market benefits of the CDPs assessed. The assumption that coal plants would be available to provide firm capacity sees CDP16, which features delayed delivery of QNI Connect and New England REZ Network Infrastructure Project, deliver slightly higher net market benefits than CDP4 in *Step Change* scenario.

**Table 71 Net market benefits and weighted net market benefits for key CDPs (in \$ billion), *Slower Coal Retirement* sensitivity and core assumptions**

CDP	Description	<i>Slower Coal Retirement sensitivity</i>			Core assumptions		
		Step Change	WNMB	WNMB rank	Step Change	WNMB	WNMB rank
<b>CDP16</b>	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	28.00	25.57	1	24.95	24.17	3
<b>CDP4</b>	CDP2 with actionable Switching Station Near Wondalga	28.26	25.47	2	25.48	24.20	1
<b>CDP2</b>	Least-cost DP for <i>Step Change</i>	28.28	25.45	3	25.48	24.16	5
<b>CDP10</b>	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	28.23	25.44	4	25.46	24.16	4
<b>CDP6</b>	CDP4 with actionable Sydney Ring South 500kV upgrade	28.08	25.43	5	25.35	24.18	2
<b>CDP20</b>	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	28.25	25.42	6	25.42	24.12	6
<b>CDP17</b>	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	27.93	25.38	7	24.81	23.94	10
<b>CDP13</b>	CDP4 without actionable Sydney Ring North (Hunter Transmission Project 1.0)	28.22	25.34	8	25.41	24.05	8
<b>CDP7</b>	CDP4 with actionable Dubbo Distribution Project	28.17	25.34	9	25.45	24.09	7
<b>CDP11</b>	CDP4 with actionable Northern Transmission Project	28.05	25.22	10	25.31	23.96	9
<b>CDP21</b>	CDP4 without actionable Project Marinus Stage 2	28.32	25.02	11	25.38	23.67	11
<b>CDP22</b>	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	28.57	24.94	12	25.28	23.43	12
<b>CDP12</b>	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	27.35	23.77	13	24.34	22.39	13

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

These sensitivities do not provide an assessment of the commercial viability of coal generation to operate in the NEM, or to increase their operational flexibility in future. It also does not consider the additional investment that would be required to enable coal-fired generators to operate in a more flexible manner, or adjust the assumed reliability of coal generators over time. The utility of these sensitivities is in demonstrating the robustness of the ODP under these varied assumptions.

### A6.7.3 Alternative gas development projections

Australia's electricity and gas markets are strongly coupled, with significant existing flexible gas capacity connected to the NEM, providing an important role in maintaining the reliability and security of the power system. The demand for gas from flexible gas generation is also a material influence on the operation of Australia's East Coast Gas Market (ECGM) that services gas consumers in NEM jurisdictions, as well as in regions outside of the NEM, particularly the Northern Territory and central Australia.

This Draft 2026 ISP includes gas development projections which identify combinations of investments that may be developed by the gas industry to address the investment opportunities highlighted in the 2025 *Gas Statement of Opportunities*<sup>41</sup> (GSOO) and support the availability and operation of flexible gas in the NEM.

Three gas development projections were developed and modelled for each Draft 2026 ISP scenario, each with different initial investments to address gas supply shortfalls prior to 2030, informed by analysis in the 2025 GSOO, and provide fuel for gas consumers including gas generators. In addition, an 'underinvestment' case was also developed, demonstrating the risks if gas developers focus only on the gas investments needed to supply direct-use gas users without consideration of the needs of flexible gas generators.

The key differences between the gas development projections include the initial investments, and then the capacity, timing and location of subsequent gas infrastructure investments, being transport, gas storage, and new gas supply, including potential regasification terminals. These options were developed and consulted with stakeholders through the *Gas Infrastructure Options Report*<sup>42</sup>.

As described in Appendix A10, each gas development projection produces a daily gas fuel availability limit affecting the NEM's capacity to use gas for electricity generation. AEMO applied the forecast gas fuel limits from gas development projection Option 3 for the cost benefit analysis. While gas development projection Option 3 informs the gas limitations for the NEM in the core scenario collection, any of the gas development projections assessed could be a reasonable and realistic outcome for the gas industry from a technical supply adequacy perspective.

**Table 72** provides the weighted net market benefits of the scenario collection with gas development projection Option 3, alongside the two other gas development projections and the underinvestment analysis. The table provides the weighted net market benefits of each CDP with the alternative gas fuel availability associated with each gas development projection, for a subset of CDPs. It demonstrates that the weighted net market benefits of the CDPs remain resilient to the fuel availability forecast in each gas development projection, with less than 10% variance in the spread of weighted net market benefits of the gas development projections across the CDPs analysed.

The estimated total cost of the various gas development projections was not included in reassessing the rankings as capital deferral of gas infrastructure does not directly benefit electricity consumers – only changes in gas prices would benefit electricity consumers, but the impact on gas prices is not trivial to assess. The relative ranking of the CDPs also remains relatively robust to the forecast gas availability of the gas development projections, including in the underinvestment analysis where less fuel is available for flexible gas and more use of backup diesel fuel may occur.

Further detail and discussion on the gas development projections is available in Appendix A2 and Appendix A10.

<sup>41</sup> See Section 5, 2025 GSOO, at [https://www.aemo.com.au/-/media/files/gas/national\\_planning\\_and\\_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf?la=en](https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf?la=en).

<sup>42</sup> See <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-gas-infrastructure-options-report-consultation>.

**Table 72 Weighted net market benefits (in \$ billion) for key CDPs under each gas development projection**

		Weighted net market benefits				Ranking based on WNMB			
		Gas development projection				Gas development projection			
CDP	Description	Option 1	Option 2	Option 3	Under-investment	Option 1	Option 2	Option 3	Under-investment
<b>CDP4</b>	CDP2 with actionable Switching Station Near Wondalga	23.89	24.12	24.20	24.55	1	1	1	1
<b>CDP6</b>	CDP4 with actionable Sydney Ring South 500kV upgrade	23.86	24.10	24.18	24.53	2	2	2	2
<b>CDP2</b>	Least-cost DP for <i>Step Change</i>	23.85	24.09	24.16	24.52	3	3	4	3
<b>CDP16</b>	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	23.85	24.08	24.17	24.50	4	4	3	4
<b>CDP23</b>	CDP4 with no non-anticipated actionable projects	18.36	18.58	18.65	18.90	5	5	5	5

Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection.

### A6.7.4 Consumer energy resource coordination

There is uncertainty about how CER coordination – through consumer VPPs and V2G charging – will shape the future of NEM. This sensitivity analysis is useful to understand the potential impact of different coordination pathways on system reliability, investment needs, and operational flexibility. To explore this, the *Step Change* scenario tested the impact of *No Further CER coordination*, meaning that beyond 2024-25, no new CER assets are coordinated within 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 the household’s needs rather than coordinated to potentially support system needs as well.

More information on the inputs of this sensitivity is in Appendix A9.

#### No Further CER Coordination

This sensitivity analysis confirms that total system costs would increase by \$7.2 billion with no further coordination of CER storages, including electric vehicles with V2G capability. Without the forecast level of CER coordination, higher levels of medium-duration utility-scale storages would be required. Note that this sensitivity is not directly comparable to the *Reduced CER Coordination* sensitivity in the 2024 ISP<sup>43</sup>, as that sensitivity on the 2024 ISP only reflected a lack of further coordination of VPPs and not the contribution of coordinated electric vehicles (V2G). Implementing similar analysis as *Reduced CER Coordination* sensitivity in the Draft 2026 ISP results in an increase in system cost of approximately \$3.1 billion.

<sup>43</sup> At <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp>

Step 5b: Sensitivity analysis to test resilience of candidate development paths

This sensitivity analysis also identifies that the total net market benefits of the proposed ODP increase by \$1.63 billion with no further coordination of CER than in the *Step Change* scenario. Without further CER coordination and transmission development, flexible gas generation must be further built and utilised in the 2040s to meet energy consumption forecast.

**Table 73 Comparison of net market benefits delivered by CDP4 in Step Change – No Further CER Coordination sensitivity versus core assumptions (\$ million)**

Class of market benefit	No Further CER Coordination sensitivity	Core assumptions	Difference
Generator, storage, and electrolyser capital deferral	19,388	18,994	394
Fixed operating and maintenance cost savings	3,628	3,344	284
Fuel cost savings	14,239	13,234	1,005
Variable operating and maintenance cost savings	837	781	55
Retirement cost	205	177	28
Voluntary and involuntary load shedding reductions	-114	-102	-13
Emissions reduction benefits	77	78	-1
REZ investment (REZ augmentations)	-823	-756	-67
Distribution expenditure (capital and operating costs)	50	59	-9
System security costs	113	156	-43
<b>Gross market benefits</b>	<b>37,600</b>	<b>35,965</b>	<b>1,635</b>
Transmission Network (Actionable and Future ISP Projects)	-10,486	-10,486	0
<b>Total market benefits</b>	<b>27,114</b>	<b>25,479</b>	<b>1,635</b>

As **Table 74** shows, the impact on weighted net market benefits of the CDPs is relatively minimal. The impacts on the generation and storage developments required without the forecast coordinated CER are relatively similar across CDPs and the counterfactual (see Appendix A2). The CDPs therefore remain relatively robust in terms of rankings, with CDP4 still the highest ranked.

**Table 74 Net market benefits and weighted net market benefits for key CDPs (in \$ billion), No Further CER Coordination sensitivity and core assumptions**

CDP	Description	No Further CER Coordination sensitivity			Core assumptions		
		Step Change	WNMB	WNMB rank	Step Change	WNMB	WNMB rank
CDP4	CDP2 with actionable Switching Station Near Wondalga	27.11	24.95	1	25.48	24.20	1
CDP6	CDP4 with actionable Sydney Ring South 500kV upgrade	26.96	24.92	2	25.35	24.18	2
CDP2	Least-cost DP for <i>Step Change</i>	27.12	24.92	3	25.48	24.16	5
CDP10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	27.09	24.92	4	25.46	24.16	4
CDP16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	26.49	24.88	5	24.95	24.17	3
CDP20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	27.05	24.87	6	25.42	24.12	6
CDP7	CDP4 with actionable Dubbo Distribution Project	27.11	24.86	7	25.45	24.09	7
CDP13	CDP4 without actionable Sydney Ring North (Hunter Transmission Project 1.0)	27.02	24.79	8	25.41	24.05	8
CDP17	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	26.49	24.72	9	24.81	23.94	10
CDP11	CDP4 with actionable Northern Transmission Project	26.93	24.71	10	25.31	23.96	9
CDP21	CDP4 without actionable Project Marinus Stage 2	27.05	24.44	11	25.38	23.67	11
CDP22	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	26.82	24.14	12	25.28	23.43	12
CDP12	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	25.68	23.00	13	24.34	22.39	13

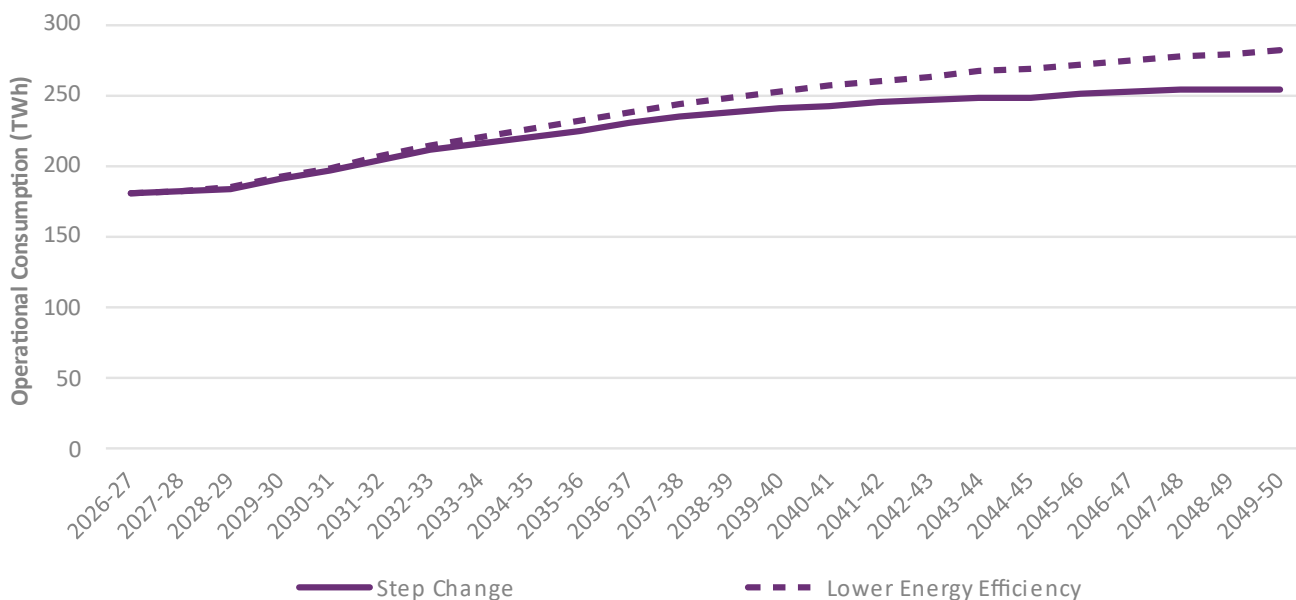
Note: Rankings above are only for the subset of CDPs assessed in this sensitivity, and differ from those in the full CDP collection

### A6.7.5 Lower energy efficiency

The *Lower Energy Efficiency* sensitivity examined the effect of reduced energy avoidance that occurs when customers invest in devices that reduce their electrical usage or improve their building thermal performance to reduce heating and cooling needs. The sensitivity is compared with *Step Change*. 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 and/or supported by policy. This sensitivity limits energy efficiency investments to only those that AEMO has estimated are supported by existing and committed energy efficiency-related policies or market-led efficiency savings and therefore does not capture as much investment in the longer term as a result. The 2025 IASR provides a comparison of the savings trajectories applied.

The impact of reduced energy efficiency on annual energy consumption in the NEM is shown in **Figure 44**. The impacts on the generation and storage developments required without the forecast energy efficiency measures are relatively similar across CDPs and the counterfactual (see Appendix A2).

**Figure 44 Impact of Lower Energy Efficiency on annual operational consumption in NEM – Step Change**



As seen in **Table 75**, the net market benefits of the proposed ODP are higher by \$2.65 billion under this sensitivity. This highlights that transmission upgrades would be increasingly valuable by enabling further renewable energy and utility-scale storage development to service the higher energy demand.

**Table 75 Comparison of net market benefits delivered by CDP4 in Step Change – Lower Energy Efficiency sensitivity versus core assumptions (\$ million)**

Class of market benefit	Lower Energy Efficiency sensitivity	Core assumptions	Difference
Generator, storage, and electrolyser capital deferral	19,040	18,994	46
Fixed operating and maintenance cost savings	3,665	3,344	321
Fuel cost savings	15,888	13,234	2,654
Variable operating and maintenance cost savings	953	781	172
Retirement cost	136	177	-40
Voluntary and involuntary load shedding reductions	-211	-102	-110
Emissions reduction benefits	81	78	3
REZ investment (REZ augmentations)	-1,063	-756	-306
Distribution expenditure (capital and operating costs)	53	59	-5
System security costs	67	156	-89
<b>Gross market benefits</b>	<b>38,610</b>	<b>35,965</b>	<b>2,645</b>
Transmission Network (Actionable and Future ISP Projects)	-10,486	-10,486	0
<b>Total market benefits</b>	<b>28,124</b>	<b>25,479</b>	<b>2,645</b>

The reduction in energy efficiency results in higher net market benefits for all CDPs assessed. As shown in **Table 76**, CDP4 remains highly ranked in this sensitivity in terms of net market benefits compared with other CDPs assessed.

**Table 76 Net market benefits and weighted net market benefits for key CDPs (in \$ billion), Lower Energy Efficiency and core assumptions**

CDP	Description	Lower Energy Efficiency sensitivity			Core assumptions		
		Step Change	WNMB	WNMB rank	Step Change	WNMB	WNMB rank
CDP16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	27.91	25.53	1	24.95	24.17	3
CDP4	CDP2 with actionable Switching Station Near Wondalga	28.12	25.41	2	25.48	24.20	1
CDP6	CDP4 with actionable Sydney Ring South 500kV upgrade	28.01	25.40	3	25.35	24.18	2
CDP2	Least-cost DP for Step Change	28.13	25.38	4	25.48	24.16	5
CDP10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	28.10	25.38	5	25.46	24.16	4
CDP20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	28.07	25.34	6	25.42	24.12	6
CDP7	CDP4 with actionable Dubbo Distribution Project	28.11	25.32	7	25.45	24.09	7
CDP17	CDP4 without actionable Queensland – New South Wales Interconnector (QNI) Connect	27.75	25.29	8	24.81	23.94	10
CDP13	CDP4 without actionable Sydney Ring North (Hunter Transmission Project 1.0)	28.05	25.27	9	25.41	24.05	8
CDP11	CDP4 with actionable Northern Transmission Project	27.99	25.19	10	25.31	23.96	9
CDP21	CDP4 without actionable Project Marinus Stage 2	28.00	24.87	11	25.38	23.67	11
CDP22	CDP4 without actionable Victoria – New South Wales Interconnector West (VNI West)	27.94	24.65	12	25.28	23.43	12
CDP12	CDP4 without actionable Sydney Ring South power flow controller option and Sydney Ring North (Hunter Transmission Project 1.0)	26.97	23.60	13	24.34	22.39	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 Step 6: Finalising the proposed optimal development path

As discussed in Section A6.5 and confirmed via sensitivity analysis in Section A6.7, **CDP4 is selected as the proposed optimal development path** in the Draft 2026 ISP, on the basis that it provides the highest weighted net market benefits and demonstrates resilience to changes in key assumption assessed in the sensitivity analyses.

Sensitivity analysis confirmed the robustness of CDP4 to key uncertainties in infrastructure delivery limitations, the pace of coal retirements, gas network developments, CER coordination and energy efficiency. In all but one sensitivity, CDP4 remains either the best or second-best CDP in weighted net market benefits, as shown in **Table 77**. Only the *Constrained Delivery* sensitivity, which favours an even more accelerated delivery of transmission augmentations, sees CDP4 rank lower than second-best. This sensitivity nonetheless demonstrates the benefits of proceeding with the projects identified as potentially actionable in CDP4, with CDPs that feature non-actionable delivery timings of these projects being relatively worse.

CDP6, with both stages of Sydney Ring South – 500 kV option actionable, is the second ranked CDP on a WNMB basis and performs well under most scenarios and sensitivities. Given the net benefit of these CDPs are similar, and both the 500 kV option and the power flow controller option are credible options to address the same system need, AEMO considers that Transgrid should continue to evaluate both options through the RIT-T.

**Table 77** Relativity of weighted net market benefits (in \$ billion) for each key CDP across the sensitivity collection

CDP	Description	Core assumptions	Constrained Delivery	Faster Coal Retirements	Slower Coal Retirements	GDP Option 1	GDP Option 2	Underinvestment GDP	No Further CER Coordination	Lower Energy Efficiency
<b>Weighted net market benefits</b>										
4	CDP2 with actionable Switching Station Near Wondalga	24.20	20.39	26.96	25.47	23.89	24.12	24.55	24.95	25.41
6	CDP4 with actionable Sydney Ring South – 500kV option (Stages 1 and 2)	24.18	20.71	26.94	25.43	23.86	24.10	24.53	24.92	25.40
16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	24.17	20.35	26.96	25.57	23.85	24.08	24.50	24.88	25.53
10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	24.16	20.43	26.92	25.44				24.92	25.38
2	Least-cost DP for <i>Step Change</i>	24.16	20.44	26.93	25.45	23.85	24.09	24.52	24.92	25.38
20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	24.12	20.34	26.89	25.42				24.87	25.34
3	Least-cost DP for <i>Accelerated Transition</i>	23.96	20.74							
<b>Change in weighted net market benefits relative to most beneficial CDP</b>										
4	CDP2 with actionable Switching Station Near Wondalga	0.00	-0.35	0.00	-0.10	0.00	0.00	0.00	0.00	-0.12
6	CDP4 with actionable Sydney Ring South – 500kV option (Stages 1 and 2)	-0.02	-0.03	-0.02	-0.14	-0.02	-0.02	-0.02	-0.03	-0.13
16	CDP4 without actionable New England REZ Network Infrastructure Project and Queensland – New South Wales Interconnector (QNI) Connect	-0.02	-0.39	0.00	0.00	-0.04	-0.04	-0.05	-0.07	0.00
10	CDP4 with actionable Eastern Victoria Reinforcement program (Option 2)	-0.03	-0.31	-0.04	-0.13				-0.03	-0.16
2	Least-cost DP for <i>Step Change</i>	-0.03	-0.30	-0.03	-0.12	-0.03	-0.03	-0.03	-0.03	-0.15
20	CDP4 without actionable Waddamana to Palmerston transfer capacity upgrade	-0.08	-0.40	-0.07	-0.16				-0.08	-0.20
3	Least-cost DP for <i>Accelerated Transition</i>	-0.24	0.00							

Note: Cells shaded teal represent the top-ranked CDP of the CDPs presented in the table for each sensitivity. Cells shaded grey indicate that the CDP was not tested for the given sensitivity.

**Table 78** presents the set of projects identified as actionable in the proposed ODP in this Draft 2026 ISP. Further details on these projects can be found in Appendix A5.

**Table 78 Network projects in the proposed optimal development path in the Draft 2026 ISP**

Committed and anticipated transmission projects		In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>B</sup>
Project EnergyConnect – Stage 2		October 2026	30 November 2027
HumeLink		1 December 2027	1 December 2027
Hunter-Central Coast REZ Network Infrastructure Project		July 2028	July 2028
Central West Orana REZ Network Infrastructure Project		1 December 2028	1 December 2028
Western Renewables Link (uprated)		30 November 2029	30 November 2029
Project Marinus Stage 1		June 2030	December 2030
CopperString		June 2031	June 2031
Projects likely to remain actionable	Actionable framework	In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>A</sup>
Gladstone Project	QLD <sup>C</sup>	1 March 2029	1 March 2029
Sydney Ring North (Hunter Transmission Project)	NSW <sup>D</sup>	November 2029	November 2029
Sydney Ring South power flow controller option	ISP	1 July 2030	1 July 2030
Waddamana to Palmerston transfer capability upgrade	ISP	June 2030	December 2030
Victoria – New South Wales Interconnector West (VNI West)	ISP	30 November 2030	30 November 2031
New England REZ Network Infrastructure Project	NSW <sup>D</sup>	July 2032	July 2032
Project Marinus Stage 2	ISP	June 2034	December 2034
Projects actionable in 2024 ISP, requiring ongoing analysis	Actionable framework	In service timing advised by proponent <sup>A</sup>	Full capacity timing advised by proponent <sup>B</sup>
Northern Transmission Project <sup>E</sup>	ISP	July 2029	July 2029
Queensland – New South Wales Interconnector (QNI) Connect <sup>F</sup>	ISP	March 2032	2034
Projects likely to be identified as newly actionable	Actionable framework	Earliest feasible in service timing <sup>A</sup>	Earliest feasible full capacity timing <sup>B</sup>
Switching Station Near Wondalga (new)	ISP	2029	2029
Western Victoria Reinforcement program (future project in 2024 ISP)	VIC <sup>G</sup>	1 June 2029	1 June 2029
Gippsland Offshore Wind Transmission (future project in 2024 ISP)	VIC <sup>G</sup>	Stage 1: 2032 Stage 2 (Phase 1): 2035 Stage 2 (Phase 2): 2039	Stage 1: 2032 Stage 2 (Phase 1): 2035 Stage 2 (Phase 2): 2039
Future ISP projects			
<b>New South Wales</b>	Central West Orana REZ Expansion, Sydney Ring South – 500 kV option		
<b>Queensland</b>	Central Queensland to Southern Queensland Expansion <sup>H</sup> , Facilitating Power to South East Queensland, Facilitating Power to Central Queensland		
<b>Victoria</b>	Eastern Victoria Reinforcement program, South West Victoria Expansion program		

- A. The in service date provides an indication for construction and commissioning to be complete and equipment is in-service.
- B. The capacity release and timing are conditional on availability of suitable market conditions and good test results.
- C. This project will progress under the Energy (Renewable Transformation and Jobs) Act 2024 (Qld) rather than the NER framework for actionable ISP projects.
- D. These projects will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the NER framework for actionable ISP projects.
- E. Previously known as the Mid North South Australia REZ project. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including confirmation of generation and storage project locations as a result of government policies and programs. Based on current cost benefit analysis, this project is not included in proposed ODP, ODP project counts, cost benefit assessment totals and other metrics in this Draft 2026 ISP.
- F. Analysis and stakeholder engagement is ongoing to confirm the status of this project, particularly including alignment with the Queensland Energy Roadmap.
- G. This project will progress under the National Electricity (Victoria) Act 2005 (Vic) rather than the NER framework for actionable ISP projects.
- H. Previously known as Queensland SuperGrid South. This project has changed from being an ‘actionable’ project in the 2024 ISP to being a ‘future’ ISP project in the Draft 2026 ISP.

## 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
<b>Actionable ISP project</b>	-	<p>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.</p> <p>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.</p> <p>Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.</p>
<b>Actionable project progressing under a jurisdictional framework</b>	-	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.
<b>Actionable New South Wales project and actionable Queensland project</b>	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
<b>Anticipated project</b>	-	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.
<b>Candidate development path</b>	CDP	<p>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.</p> <p>Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the <i>ISP Methodology</i>.</p>
<b>Capacity</b>	-	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.
<b>Committed project</b>	-	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.
<b>Consumer energy resources</b>	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles. CER may include demand flexibility.
<b>Consumption</b>	-	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.
<b>Cost-benefit analysis</b>	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.
<b>Demand</b>	-	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, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.

Term	Acronym	Explanation
<b>Demand-side participation</b>	DSP	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.
<b>Development path</b>	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
<b>Dispatchable capacity</b>	-	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.
<b>Distribution network service provider</b>	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
<b>Economic offloading</b>	-	Refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price. This may also be referred to as economic 'spill' or 'spilled energy' as generators reduce output due to low market prices or lack of available demand.
<b>Firming</b>	-	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 flexible gas.
<b>Future distribution project</b>	-	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).
<b>Future ISP project</b>	-	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.
<b>Identified need</b>	-	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.
<b>ISP development opportunity</b>	-	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.
<b>National Electricity Rules</b>	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.
<b>Net market benefits</b>	-	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.
<b>'No transmission' counterfactual development path</b>	-	The 'no transmission' counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the Counterfactual DP to calculate the economic benefits of transmission.
<b>Non-network option</b>	-	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.
<b>Optimal development path</b>	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.
<b>Regulatory Investment Test for Transmission</b>	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.

Term	Acronym	Explanation
<b>Reliable (power system)</b>	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
<b>Renewable energy</b>	-	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.
<b>Renewable energy zone</b>	REZ	An area identified in the ISP as high-quality resource areas where clusters of utility-scale renewable energy projects can be developed using economies of scale.
<b>Renewable drought / Renewable energy lull</b>	-	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.
<b>Rooftop and other small-scale solar</b>	-	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.
<b>Scenario</b>	-	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 the Draft 2026 ISP, AEMO has considered three scenarios: <i>Slower Growth</i> , <i>Step Change</i> and <i>Accelerated Transition</i> .
<b>Secure (power system)</b>	-	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).
<b>Sensitivity analysis</b>	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
<b>Spilled energy</b>	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price. This can also be referred to as ‘economic offloading’.
<b>Transmission network service provider</b>	TNSP	A business that owns, controls or operates a transmission network.
<b>Utility-scale or utility</b>		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.
<b>Value of greenhouse gas emissions reduction</b>	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.
<b>Virtual power plant</b>	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.
<b>Variable renewable energy</b>	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.