Draft 2025 Electricity Network Options Report

May 2025

Draft report for consultation

For the 2026 Integrated System Plan (ISP)

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 Group 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

AEMO publishes this Draft 2025 *Electricity Network Options Report* as part of an initiative to improve the accuracy and transparency of transmission network augmentation options and distribution network opportunities used for the 2026 *Integrated System Plan*. This report is part of the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), which is published in accordance with National Electricity Rules (NER) 5.22.8. This publication is generally based on information available to AEMO as at 22 May 2025 unless otherwise indicated.

Disclaimer

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

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

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Version control

Version	Release date	Changes
1.0	22 May 2025	Initial version.

Contents

Executive summary

Efficient investment in the electricity network is essential to ensure consumers have access to secure, reliable and affordable electricity through the energy transition

Australia needs an energy system that delivers secure, reliable and affordable electricity through the transition to net zero by 2050. Published every two years, AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, presenting the plan for essential infrastructure that meets both consumer needs and government energy and emissions targets between now and 2050.

As a key input to the development of the ISP, the Draft 2025 *Electricity Network Options Report* outlines a range of transmission network augmentation options and distribution network opportunities. These will be assessed in the 2026 ISP, with the objective of identifying investments to provide consumers with access to secure, reliable and affordable electricity.

Investment in the electricity transmission network, along with other investments identified in the ISP optimal development path (ODP), will be essential in the coming years to increase the transfer capacity of renewable energy zones (REZs) and the backbone of the interconnected network. The distribution network will play an increasingly important role, linking individual consumers, their consumer energy resources (CER) such as rooftop solar and household batteries, and other distributed resources into one integrated power system. New investment in these electricity networks will be essential to efficiently provide consumers with access to secure and reliable energy, and enable a net zero economy.

This report identifies a range of draft electricity network options to be evaluated in the 2026 ISP

This is part of a suite of reports that document inputs to the ISP and is focused on options for development of the electricity networks. Other potential developments, non-network and supply side solutions, are documented in other reports developed as part of the ISP preparation. AEMO welcomes feedback from all stakeholders about additional and alternative options which could be considered for inclusion in the final report.

AEMO has collaborated with transmission network service providers (TNSPs), distribution network service providers (DNSPs) and jurisdictional bodies through extensive consultation and joint planning to inform the preparation of this report.

This report includes the following updated information:

- **an update to AEMO's cost estimation and forecasting approach,** undertaken by consultants GHD and Amplitude and informed by information provided by transmission network planning bodies, to reflect the most recent cost estimation processes and data for transmission network infrastructure
- **updated transmission augmentation options**, including conceptual design, lead time, location and cost estimates – these are categorised as "flow paths" for options that augment the capacity of the main transmission network pathways over which bulk energy is shipped, and "REZs" for options that augment the capacity to connect clusters of large-scale renewable energy in high-resource areas, and
- **updated generation and storage connection costs** to connect individual projects to the broader electricity network.

Also, for the first time, this report contains new information about **distribution network opportunities**, including capabilities and augmentation costs to be included for the first time in an ISP, with a focus on opportunities to facilitate aggregate operation of CER and other distributed resources (such as community batteries).

Transmission costs have risen, particularly for overhead lines

This report includes a comprehensive update to AEMO's Transmission Cost Database prepared by consultants and informed by recent transmission project tendering outcomes in the NEM. Updating the Transmission Cost Database is essential to ensure the most recent project cost information can be used to inform the 2026 ISP.

The recent update to AEMO's Transmission Cost Database shows that the Australian energy sector continues to be subject to ongoing supply chain issues associated with the delivery of materials and equipment, as well as workforce and skills shortages.

After accounting for inflation, cost estimates provided in this report show approximately a 25% to 55% increase in real costs for overhead transmission line projects compared to equivalent cost estimates prepared for the 2024 ISP, and approximately a 10% to 35% increase in real costs for transmission substation projects. This is in line with increases announced for recent projects.

TNSPs and other jurisdictional planning bodies have advised AEMO that the recently observed cost increases in tendering processes and project delivery are primarily driven by:

- **sustained supply chain pressures** on materials, equipment and workforce
- **market competition** driven by a high number of concurrent projects under development in the NEM
- **project complexity**, including an increased number of projects planned for remote areas
- **social licence** and additional community and landholder engagement along proposed transmission line routes, and
- **additional contracting costs** to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

AEMO recognises that increases in costs for electricity transmission network development would impact bills for electricity consumers. When preparing the 2026 ISP, AEMO will consider these changes in costs as part of identifying an efficient ODP that is in the long-term interests of electricity consumers. The 2026 ISP will re-visit transmission network projects previously identified as needing to proceed, with the exception of projects that have advanced to anticipated or committed status, seeking to ensure that overall costs for consumers are optimised. A conceptual map of transmission options is provided in **Figure 1**.

Social licence for transmission has been further considered

AEMO has continued to incorporate social licence considerations into the conceptual transmission network options considered in the ISP, and acknowledges that this is an area of continued learning and development. This report includes options that have been jointly planned with TNSPs and jurisdictional bodies to incorporate community sentiment or acceptance of energy infrastructure as understood by TNSPs and jurisdictional bodies. As the energy transition proceeds, social licence considerations are of great importance to organisations across the energy sector.

In this report, AEMO incorporates the results of new land use analysis into the transmission network options. Additional costs have been included in network options to represent the potential need to change proposed transmission line routes to avoid traversing particularly complex areas for delivering transmission infrastructure, signalling potential realignment of transmission lines to less complex areas. AEMO has not included community sentiment research results in these early, conceptual options as this research is not sufficiently granular and because community sentiment changes over time. AEMO understands the high importance of prioritising community and stakeholder engagement as projects develop beyond the conceptual stage.

Distribution network opportunities have been identified

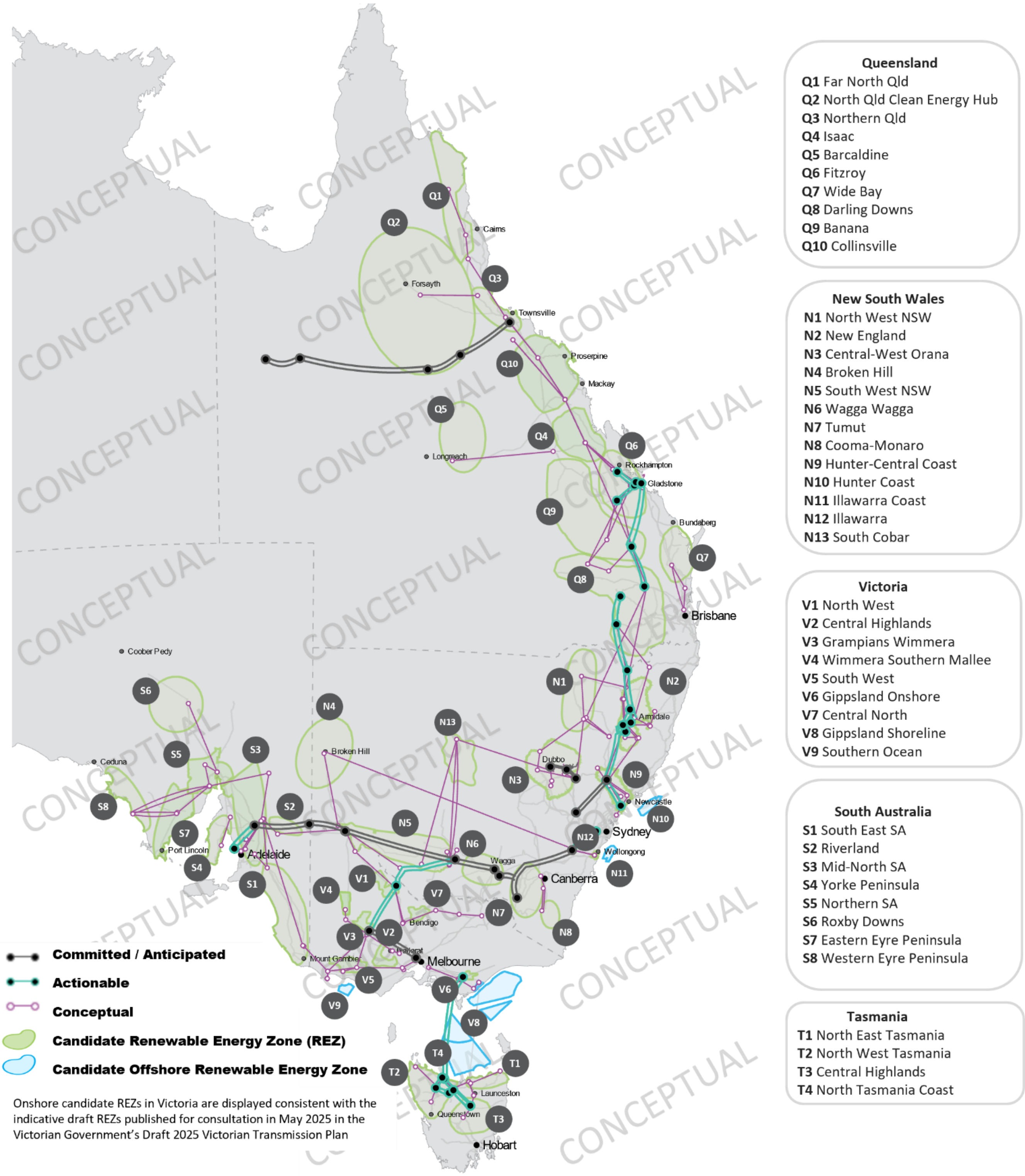
Following Australia's Energy Ministers' endorsement of the actions recommended by the Federal Government's ISP Review, the Australian Energy Market Commission (AEMC) made rule changes in December 2024 requiring AEMO to consider how distribution network investments impact the development of CER and other distributed resources, as well as the impact that both have on the ODP identified in the ISP.

The ISP has historically focused on CER uptake as an input, and the optimisation of transmission network investment and utility-scale generation and storage development as an output. AEMO has now begun engaging with distribution networks to incorporate important insights about their networks and the impact on CER into future ISPs.

This report provides, for the first time, proposed distribution network opportunities to facilitate the operation of CER and other distributed resources. These would add to the existing ability of the distribution networks to connect and operate CER across the NEM and may be required to operate the forecast uptake of CER (and other distributed resources) in the various ISP scenarios. After existing network capacity is used in the model, this report provides an estimated average cost of $0.4 million per megawatt (MW) of network capacity for voltage management optimisation to facilitate operation of aggregate CER, and an estimated average cost of $2.4 million per MW for subsequent larger network augmentations to facilitate export capacity upgrades in some cases. This report also provides a methodology for applying these opportunities in the ISP model.

AEMO and DNSPs have collaborated extensively to prepare these proposed inputs and assumptions for stakeholder feedback. AEMO welcomes stakeholders' feedback and views on this report, and looks forward to continuing to consult with industry, consumers and other stakeholders throughout the delivery of the 2026 ISP.

Figure 1 Conceptual map of transmission network options for the Draft 2025 *Electricity Network Options Report*



Key changes from the 2023 *Transmission Expansion Options Report*

Compared to the 2023 *Transmission Expansion Options Report*, AEMO has made the following changes in this Draft 2025 *Electricity Network Options Report*:

- **Updated transmission options** across the NEM through collaboration and extensive joint planning with TNSPs and jurisdictional bodies, incorporating the most up to date and detailed information wherever possible. Key updates include:
  - **Update of the AEMO Transmission Cost Database** to incorporate recently-observed cost increases, and application of the updated database to prepare cost estimates for future transmission options in this draft report (except for projects where a project proponent provided a cost estimate). Key cost increase drivers are sustained supply chain pressures on materials, equipment and workforce, and market competition driven by a high number of concurrent projects under development, as well as project complexity, social licence and additional contracting costs.
  - After accounting for inflation, cost estimates provided in this report show **approximately a 25% to 55% increase in real costs for overhead transmission line projects** compared to equivalent cost estimates prepared for the 2024 ISP, and **approximately a 10% to 35% increase in real costs for transmission substation projects.** This is in line with increases announced for recent projects.
  - **Further consideration of social licence for transmission network options**, through inclusion of additional costs in network options to represent the potential need to change proposed transmission line routes to avoid traversing particularly complex areas for delivering transmission infrastructure. Extensive joint planning with TNSPs and the use of updated land use complexity analysis informed this update to future network options.
  - Alignment with the latest plans from TNSPs and jurisdictional bodies, including but not limited to: Powerlink's latest priority transmission investment activities for the Gladstone Project; ongoing investigation of actionable ISP projects in New South Wales by Transgrid; current REZ options from EnergyCo in New South Wales; recent regulatory investment test for transmission (RIT-T) materials from AEMO Victorian Planning and the recently released Draft Victorian Transmission Plan from VicGrid; augmentation options for updated REZ definitions and flow paths in South Australia from ElectraNet; and information on Project Marinus from MarinusLink and TasNetworks.
- **Included distribution opportunities for the first time, and updated the document title** from *Transmission Expansion Options Report* to *Electricity Network Options Report* to reflect the expanded scope of this report.
  - The addition of electricity distribution network opportunities is in response to Energy Ministers' approval of the recommendations of the Federal Government's ISP Review and new requirements subsequently introduced in the National Electricity Rules (NER) implementing these recommendations.
  - AEMO and DNSPs have engaged extensively to prepare the draft materials released for consultation in this report.
- **Updated generator and storage connection and system strength costs** to incorporate the latest market information used to prepare the updated Transmission Cost Database, and to align with the Draft ISP Methodology which includes modelling of system strength remediation costs (both to maintain minimum secure levels, and to support the development of new renewable energy in REZs.

Notice of consultation

AEMO is publishing this draft report on the transmission augmentation options and distribution network opportunities under consideration for the 2026 ISP, including conceptual design, lead time, location and cost estimates for transmission network options, and network limitations and augmentation cost rates for distribution network options.

The final report will form part of the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines[1].

Stakeholder submissions are welcomed in response to the Draft 2025 *Electricity Network Options Report*

All stakeholders are invited to make a submission to any matters discussed in this draft report, or in the attached consultants' reports on the update to AEMO's Transmission Cost Database, the land use complexity analysis, and assumptions about parameters relating to mid-size solar PV and batteries. AEMO has also provided a specific list of key consultation questions on page 11.

Submissions in response to this Draft 2025 *Electricity Network Options Report* should be sent to ISP@aemo.com.au, by 5.00pm (AEST) on Monday 23 June 2025.

Please identify any parts of your submission that you wish to remain confidential, and explain why. AEMO may still publish that information if it does not consider it to be confidential, but will consult with you before doing so. Material identified as confidential may be given less weight in the decision-making process than material that is published.

Submissions received after the closing date and time will not be valid, and AEMO is not obliged to consider them. Any late submissions should explain the reason for lateness and the detriment to you if AEMO does not consider your submission.

AEMO will host a 90-minute webinar on Friday 6 June 2025, from 9.00 am to 10.30 am (AEST) to present key materials in this report, and allow time for questions. All interested stakeholders can sign up to attend the webinar[2]. Consumer advocates are welcome to attend a verbal consultation submission session on Thursday 19 June 2025, from 11.00 am to 12 pm (AEST) and can register to attend[3].

AEMO will publish a consultation summary report alongside the final 2025 *Electricity Network Options Report* in July 2025, explaining how stakeholders' submissions have been considered in the preparation of the final report.

Supplementary materials

Table 1 outlines related files and reports that have been used to prepare transmission augmentation options and distribution network opportunities in this Draft 2025 *Electricity Network Options Report*. Stakeholders are invited to refer to these documents for further background and context.

[1] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

[2] At https://events.teams.microsoft.com/event/69f09751-87d6-4ac7-bbe9-11d0f349f68f@320c999e-3876-4ad0-b401-d241068e9e60.

[3] At https://events.teams.microsoft.com/event/47b6de3c-1fb0-4d44-972c-ba8f7b668701@320c999e-3876-4ad0-b401-d241068e9e60.

Table 1 Related files and reports

Document	Description	Location
GHD 2025 Transmission Cost Database update report	Describes the update made to the AEMO Transmission Cost Database in 2025 by consultants GHD and Amplitude.	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/ghd-2025-transmission-cost-database-update-final-report
GHD 2025 Transmission cost forecasting method update report	Describes the update made to the AEMO transmission cost forecasting method in 2025 by consultant GHD.	https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report
Transmission Cost Database (Version 3.0)	Database of cost estimate inputs and Microsoft Excel-based cost estimating tool used for estimating future ISP transmission augmentation options and, in some cases, where cost estimates are not available from a project proponent. Version 3.0 includes a 2025 update to the database.	Available by request. Please complete the form on AEMO's web page to receive the updated Transmission Cost Database: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios/transmission-cost-database
Draft transmission cost estimate calculations	A compressed ZIP file containing AEMO Transmission Cost Database output files for each project option in the Draft 2025 *Electricity Network Options Report* that has been estimated using the Transmission Cost Database. In cases where a project cost estimate is based on confidential materials provided by the project proponent based on tendering information or similar, the cost estimates may not be included for download. These records show the makeup of AEMO's transmission cost estimates – including building blocks, adjustments, risk and indirect costs.	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/draft-transmission-cost-estimate-calculations
Jacobs 2025 Strategic land use transmission assessment report **Jacobs 2025 Strategic land use transmission assessment GIS data**	Reports on the results of a land use complexity multi-criteria analysis exercise undertaken by Jacobs to inform the preparation of transmission augmentation options for the 2026 ISP. Both a report and a geographic data (KML) file are provided for explaining this material.	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/jacobs-strategic-land-use-transmission-assessment-report https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/jacobs-strategic-land-use-transmission-assessment-GIS-data
Aurecon 2025 Generation and storage technical parameter and cost report for distributed resources	Proposes generation and storage item cost estimates for 'other distributed resources', for consideration in analysis of distribution network opportunities in the 2026 ISP, prepared by Aurecon.	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/aurecon-2025-generation-and-storage-technical-parameter-and-cost-report-for-distributed-resources

Consultation process and timeline

Table 2 shows the consultation process for the 2025 *Electricity Network Options Report*, which is being undertaken as part of the 2025 IASR, as well ask key milestones for other 2026 ISP development consultations that are underway. The notice of consultation above provides details for feedback opportunities in response to this Draft 2025 *Electricity Network Options Report*.

Table 2 Consultation process for the 2025 *Electricity Network Options Report*, and other 2026 ISP consultations underway

Activity	Date
ISP Methodology issues paper published	23 October 2024
Draft 2025 IASR Stage 1 published	11 December 2024
Draft 2025 IASR Stage 2 published	28 February 2025
Draft ISP Methodology and consultation paper published	13 March 2025
Draft 2025 *Electricity Network Options Report* published	22 May 2025
Draft 2025 *Gas Infrastructure Options Report* published	22 May 2025
Draft 2025 *Electricity Network Options Report* webinar	6 June 2025
Draft 2025 *Electricity Network Options Report* verbal submission session for consumer advocates	19 June 2025
Draft 2025 *Electricity Network Options Report* submissions due date	23 June 2025
ISP Methodology and consultation paper published	25 June 2025
2025 *Electricity Network Options Report*, 2025 *Gas Infrastructure Options Report* and 2025 IASR published	By 31 July 2025
Final 2025 *Electricity Network Options Report* webinar	August 2025
Draft 2026 ISP published	December 2025

Note: This table shows webinar and verbal submission details only for the *Electricity Network Options Report.* For details on webinars and verbal submissions for the 2025 IASR and the 2025 *Gas Infrastructure Options Report,* please see the consultation webpages for those reports, at https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report and https://aemo.com.au/consultations/current-and-closed-consultations/2025-gas-infrastructure-options-report.

Consultation questions provided in this paper

Methodology

1. Do stakeholders agree with the approach taken to reflect recently observed transmission market cost increases in the updated Transmission Cost Database? Do the updated Transmission Cost Database and subsequent cost estimate updates in this report reflect stakeholders' market observations in the NEM?
2. What feedback do stakeholders have about any further work required to support finalising the updated Transmission Cost Database?
3. Do you agree with AEMO's proposal for considering the inclusion of concessional finance for transmission projects in the ISP cost benefit analysis? Should AEMO align the treatment of concessional finance in the ISP with that in a RIT-T assessment? Should projects progressed via jurisdictional frameworks be treated in the same way?
4. What feedback do stakeholders have about AEMO's proposed forecasting approach for transmission costs over the ISP horizon?
5. What feedback do stakeholders have about AEMO's proposal to apply different forecasts for transmission project costs across each scenario?
6. Do you have any feedback on AEMO's land use mapping approach, or other aspects AEMO could consider for future improvements?

7. Is the planned approach for calculating opportunities for CER and associated distribution network costs reasonable? Noting time and data constraints, are there other factors AEMO and DNSPs could reasonably consider?
8. Is the planned modelling approach reasonable for the uptake of other distributed resources? Noting time and data constraints, are there other factors AEMO and DNSPs could reasonably consider?

Flow paths

9. Do stakeholders have any feedback on the proposed augmentation options for the flow paths in the NEM?
10. Do stakeholders have any proposed additional or alternative network options for the flow paths in the NEM, that should be considered for the final 2025 *Electricity Network Options Report*?
11. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the flow paths.

Renewable energy zones (REZs)

12. Do stakeholders have any feedback on the proposed augmentation options for the candidate REZs in the NEM?
13. Do stakeholders have any proposed additional or alternative network options for the candidate REZs in the NEM, that should be considered for the final 2025 *Electricity Network Options Report*?
14. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the candidate REZs.

Distribution network opportunities

15. Do you agree with the proposed DNSP cost tranches and the methodology AEMO has used to identify these? If not, do you have recommendations for how the methodology can be enhanced?

Generator and storage connection costs

16. What feedback do stakeholders have about the proposed treatment of generation and storage connection costs, including treatment of system strength costs?

1 Introduction

Published every two years, AEMO's ISP is a roadmap for the transition of the NEM power system, presenting the plan for essential infrastructure that meets both consumer needs and government energy and emissions targets between now and 2050. Previous ISPs have called for urgent investment in electricity generation, storage and transmission to deliver secure, reliable and affordable electricity to consumers through the transition.

Leveraging expertise from across industry and consumer representatives is pivotal to the development of a robust plan that supports the long-term interests of energy consumers. AEMO is committed to providing an accessible engagement program that offers stakeholders a range of opportunities to shape the 2026 ISP.

This Draft 2025 *Electricity Network Options Report*[4] forms part of the 2025 IASR. It describes the preparation of advice from consultants and provision of industry and stakeholder advice, culminating in a report that summarises a range of transmission network augmentation options and distribution network opportunities for the 2026 ISP. These options include conceptual transmission options as well as distribution network opportunities for facilitating the aggregate operation of CER such as rooftop solar and batteries, and other distributed resources.

This report addresses actions identified in the Federal Government's ISP Review, which were approved by Energy Ministers and further implemented by NER changes.

AEMO welcomes feedback on all aspects of this Draft 2025 *Electricity Network Options Report*, and has also provided specific consultation questions for consideration (see the purple boxes throughout the report, and the summary listed on page 11).

This section outlines the context for this report, including:

- addressing actions from the ISP Review (Section 1.1)
- application of transmission network options in the ISP (Section 1.2)
- call for non-network alternatives to transmission options (Section 1.3)
- application of distribution network opportunities in the ISP (Section 1.4), and
- 2026 ISP development process (Section 1.5).

1.1 Addressing actions from the ISP Review

Over 2023 and early 2024, the Federal Government undertook a review of the ISP[5], and on 5 April 2024, the Energy and Climate Change Ministerial Council published the *Energy Ministers' Response to the ISP Review*[6]. The response outlined a series of actions to enable the ISP to set a direction for the energy system as a whole, while

[4] Previously known as the *Transmission Expansion Options Report*, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation, and the *Transmission Cost Report*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/2022-isp-inputs-assumptions-and-scenarios.

[5] Australian Government, Department of Climate Change, Energy, the Environment and Water. *Review of the Integrated System Plan – Final Report*, January 2024. At https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Energy_Planning_and_Regulation_in_Australia/EnergyPlanning/Additional_Documents.

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

maintaining the critical function of the ISP in transmission planning. The ISP Review focused on supporting emissions reduction, integrating gas and electricity planning, enhancing demand considerations, transformation of Australia's energy mix, jurisdictional policy interactions, and the timely delivery of ISP projects.

In December 2024, the AEMC amended the NER and National Gas Rules (NGR) to implement aspects of the review of the ISP:

- **For improving consideration of demand-side factors in the ISP**[7], the rules now require AEMO to publish a demand-side factors statement in the ISP (and information guidelines to be prepared by December 2025 to explain which categories of information will be collected to inform the statement and how the information will be collected). In addition, the rules place an obligation on DNSPs to provide relevant information to AEMO for the statement in accordance with the guidelines. The AEMC's final rule determination acknowledges that the requirement to develop the information guidelines under the rules consultation procedures means that AEMO is unlikely to have fully comprehensive demand-side information in time to include in the 2026 ISP, however, expects DNSPs and AEMO to continue constructive collaboration and find the best way to leverage existing information for use in the 2026 ISP. AEMO and DNSPs have been collaborating extensively to prepare initial data, provided on a voluntary basis, that can be used for the 2026 ISP. It is expected that further and improved information will be available for the 2028 and subsequent ISPs. AEMO is required to publish the information provided by DNSPs under the information guidelines in the ISP database.
- **For better integration of gas and community sentiment into the ISP**[8], the rules now enable AEMO to access, use and disclose specified gas information collected under the NGR, subject to confidentiality provisions, to expand and deepen the gas analysis included in the ISP. The information will be used by AEMO to develop gas development projections that will be included in the ISP. No rule changes were made for enhancing inclusion of community sentiment information in the ISP, as the AEMC considers that existing rules and joint planning processes between AEMO and TNSPs are sufficiently flexible to enable AEMO to better integrate consideration of community sentiment into the ISP.

In this Draft 2025 *Electricity Network Options Report*, AEMO provides the following in response to the relevant ISP Review outcomes:

- **DNSP data relating to distribution network opportunities for facilitating the aggregate operation of CER and other distributed resources**. This data has been received by AEMO following extensive engagement with the DNSPs in the NEM, from May 2024 onwards, in a joint effort to support the implementation of the ISP Review outcomes ahead of the formal reporting requirements coming in to effect. AEMO thanks the representatives from DNSPs for their advice and information provision. The DNSP data can be found in Section 5 of this report.
- **A proposed approach for incorporating DNSP data in to the 2026 ISP.** This approach includes taking DNSP data relating to network capabilities and augmentation costs, applying a disaggregated load forecast and CER

[7] AEMC. *Rule determination. National Electricity Amendment (Improving consideration of demand-side factors in the ISP) Rule 2024*, December 2024. At https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp.

[8] AEMC. *Final report. National Electricity Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024 and National Gas Amendment (Better integration of gas and community sentiment into the ISP) Rule 2024,* December 2024. At https://www.aemc.gov.au/rule-changes/better-integration-gas-and-community-sentiment-isp-0.

forecasts, calculating resulting DNSP network limits, and synthesising outcomes to be applied in the ISP model at the sub-regional level. The proposed approach can be found in Section 2.12 of this report.

- **A proposed approach for better integration of community sentiment into the ISP.** As suggested in the AEMC's final determination on the relevant rule change, this matter has been considered through existing joint planning arrangements between AEMO, TNSPs and relevant jurisdictional bodies, as well as through AEMO's engagement with the ISP Consumer Panel and AEMO's Consumer and Community Reference Group. AEMO has procured land use complexity analysis to support integration of some consumer sentiment considerations in the transmission augmentation options proposed in this report, and publishes the associated analysis for stakeholders' information. The proposed approach can be found in Section 2.11 of this report.

Table 3 shows the publications that AEMO proposes to amend to address each ISP Review action or rule change, to help inform engagement by stakeholders on appropriate publications.

Table 3 Proposed implementation for actions in the Energy Ministers' Response to the ISP Review

Action in the response to the Review of the ISP	Process for implementation				
	2025 IASR	*ISP Methodology*	2025 *Electricity Network Options Report*[A] and 2025 *Gas Infrastructure Options Report*	*Enhanced Locational Information* report[B]	Draft ISP and final ISP
Integrating gas into the ISP	✔	✔	✔		✔
Enhanced demand forecasting and optimising for the demand side	✔	✔	✔		✔
Better data on industrial and consumer electrification					✔
Coal-fired generation shutdown scenarios					✔
Improving locational information				✔	✔
Enhanced analysis of system security	✔	✔			✔
Jurisdictional policy transparency	✔ [D]				✔
Clarifying policy inclusions	✔ [D]				✔
Improving the accessibility of the ISP[C]	✔				✔
Incorporating community sentiment	✔		✔		✔
Additional planning inputs	✔				✔

A. The *Electricity Network Options Report* forms part of the IASR. It was previously known as the *Transmission Expansion Options Report*, but has been renamed to reflect the inclusion of both transmission and distribution in future ISPs.
B. The *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.
C. AEMO will consider opportunities throughout the ISP development process to enhance consumer understanding of key elements.
D. These actions are to be implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions.

1.2 Application of transmission network options in the ISP

Electricity transmission network augmentation options – particularly their conceptual design, lead time, location and cost estimates – are key inputs to development of the ISP. A combination of these options will be used in the selection of the ODP. The ODP can identify new actionable transmission projects, and can also include new generation and storage to efficiently deliver firmed renewable energy to consumers through the NEM[9].

Electricity distribution network capabilities and augmentation costs for facilitating the aggregate operation of CER and other distributed resources are a new and important input to the development of the ISP. The distribution network options consulted on in this report are inputs in the development of the ISP.[10]

AEMO seeks to co-design conceptual network options for the ISP with TNSPs, NEM jurisdictional bodies and DNSPs. AEMO, TNSPs, jurisdictions and DNSPs have collaborated to undertake the extensive collaboration and joint planning necessary to prepare this draft report. These bodies include:

- **For transmission** – Powerlink, Transgrid, EnergyCo, AEMO in its capacity as the Victoria Transmission Planner, VicGrid, AusNet Services in its Victorian transmission planning capacity, ElectraNet, MarinusLink, TasNetworks in its Tasmanian transmission planning capacity,
- **For distribution** – Ausgrid, AusNet Services in its Victorian distribution planning capacity, CitiPower, Powercor, United Energy, Endeavour Energy, Energy Queensland, Essential Energy, Evoenergy, Jemena, SA Power Networks, TasNetworks in its Tasmanian distribution planning capacity, and Energy Networks Australia (ENA).

In some cases, the Draft 2025 *Electricity Network Options Report* incorporates advice from project proponents for committed and anticipated[11] transmission network augmentation projects.

The 2026 ISP will use transmission network augmentation options and distribution network opportunities from the final 2025 *Electricity Network Options Report*, which will form part of the 2025 IASR published on the AEMO website[12]. Where updated cost estimate information is provided to AEMO by TNSPs for future ISP projects with preparatory activities, and for projects undergoing the RIT-T process or other jurisdictional review processes, AEMO will cross-check this information[13] using the latest *Transmission Cost Database* before it is included in the final *2025 Electricity Network Options Report* and final 2025 IASR.

[9] For further information about the ISP modelling approach and the selection of the ODP please see the ISP Methodology. The current version of the methodology is at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology. AEMO is currently consulting on updates to the methodology, for application in the 2026 ISP. Information on this consultation is at https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[10] The new requirement on AEMO to publish a demand-side factors statement in the ISP, introduced by the AEMC's 'Improving consideration of demand-side factors in the ISP' rule change, requires AEMO to outline opportunities for development of distribution networks that are consistent with the efficient development of the power system. For the 2026 ISP, AEMO will use information provided by DNSPs in the 2026 ISP and other information available to AEMO. For subsequent ISPs, DNSPs will be required by the NER to comply with information requirements and processes in information guidelines to be published by AEMO.

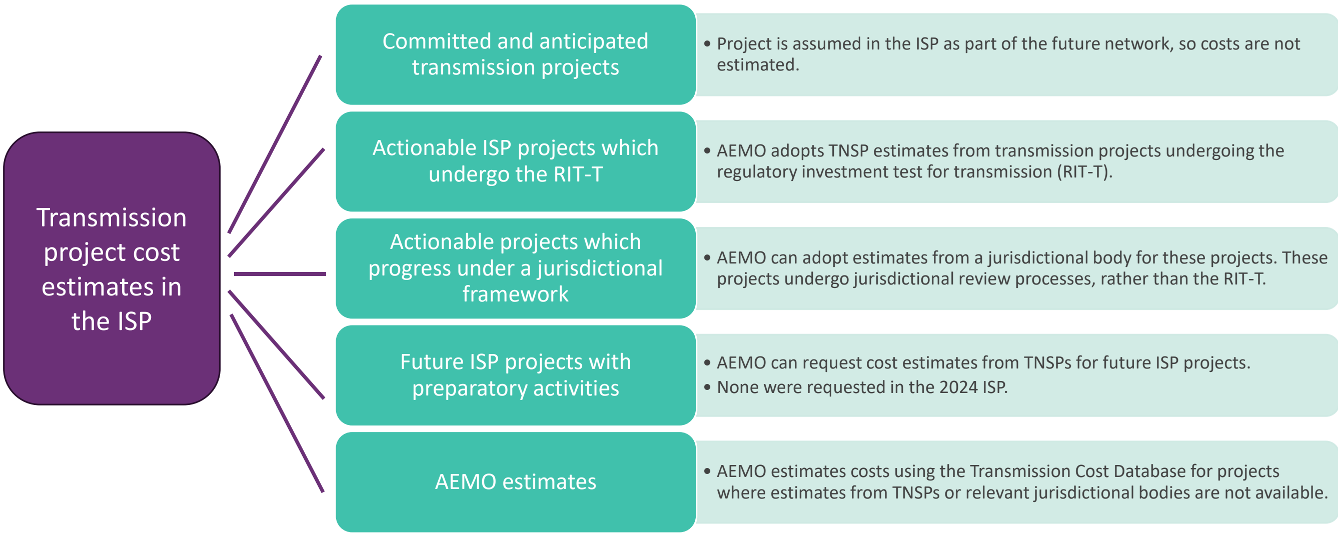
[11] Transmission network augmentation projects are categorised as committed or anticipated after meeting a certain threshold: Committed projects meet five criteria relating to planning, construction, land, contracts and financing; anticipated projects are in the process of meeting at least three of the criteria for committed projects. Further details about the criteria for committed and anticipated project statuses are in the AER's Regulatory investment test for transmission (RIT-T) publication, and are also summarised in AEMO's Transmission Augmentation Information page.

[12] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[13] Section 2.3 provides information about the transmission project cost estimate cross-checking process.

Figure 2 shows AEMO's approach to incorporating transmission project cost estimates in the ISP for different project categories. The following sections provide further information about the projects that fall within each category.

Figure 2 AEMO's approach to incorporating transmission projects in the IASR and ISP



Committed and anticipated transmission projects

Transmission projects being developed and delivered by TNSPs or relevant NEM jurisdictional bodies may be categorised as committed or anticipated:

- Committed transmission augmentation projects meet five criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment, and necessary financing arrangements.
- Anticipated projects are in the process of meeting at least three of the criteria.

Details about the criteria for committed and anticipated project status are provided in AEMO's Transmission Augmentation Information publication[14] and are consistent, where relevant, with the five criteria defined for committed and anticipated projects in the AER's Cost Benefit Analysis Guidelines[15] and the RIT-T instrument[16].

AEMO includes all committed and anticipated projects in all future states of the world for the purposes of forecasting and planning publications, in accordance with the AER's Cost Benefit Analysis Guidelines. Because these projects are assumed to proceed, the projects' costs are not re-evaluated for the purposes of the ISP. **Table 4** lists transmission projects that are currently classified as committed or anticipated. AEMO may use updated information in the ISP, for example, as included in the latest Transmission Augmentation Information publication.

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

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

[16] AER. Regulatory investment test for transmission. August 2020. At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

Table 4 Committed and anticipated transmission projects for the 2026 ISP

Project[A]	Status	Responsible TNSP(s) or jurisdictional bodies	More information
Waratah Super Battery Network Augmentations and SIPS Control	Committed	EnergyCo	https://www.energyco.nsw.gov.au/projects/waratah-super-battery
Mortlake Turn-In	Committed	AEMO on behalf of Victorian Government	Pg. 68, 2022 *Victorian Annual Planning Report*, AEMO
Murray River REZ and Western Victoria REZ minor augmentations	Committed	AEMO on behalf of Victorian Government	Pg. 67, 2022 *Victorian Annual Planning Report*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report
Victoria Central North REZ minor augmentations	Committed	AEMO on behalf of Victorian Government	Pg. 68, 2022 *Victorian Annual Planning Report*, AEMO
Ararat synchronous condenser	Committed	AEMO on behalf of Victorian Government	Pg. 69, 2022 *Victorian Annual Planning Report*, AEMO
Humelink	Anticipated	Transgrid	2024 Transmission Annual Planning Report, Transgrid
Project EnergyConnect – Stage 2	Committed	ElectraNet, Transgrid, AusNet Services	https://www.electranet.com.au/projects/project-energyconnect/ https://www.transgrid.com.au/projects-innovation/energyconnect/
Western Renewables Link	Anticipated	AEMO (Victorian Planning)	https://www.westernrenewableslink.com.au/
Central-West Orana REZ Network Infrastructure Project	Anticipated	EnergyCo	https://www.energyco.nsw.gov.au/cwo
CopperString 2032	Anticipated	Powerlink	https://statements.qld.gov.au/statements/97314

A. Some smaller committed and anticipated transmission augmentation projects have not been included here, but may be found in AEMO's Transmission Augmentation Information page or the websites of the relevant TNSPs or jurisdictional bodies. For ISP power system analysis purposes, the most up-to-date model of the network is used, including relevant small and large projects.

Actionable ISP projects which undergo the RIT-T

Actionable ISP projects undergo the RIT-T. The proponent TNSP proceeds through a consultation process to prepare and select options to meet the project need. Further review processes – such as the ISP feedback loop and a Contingent Project Application to the AER – are also undertaken before a TNSP is enabled to recover revenue for the project, except in the case of early works which may be progressed as soon as a project is made actionable and before it commences a RIT-T[17].

For the ISP modelling process, AEMO requests updated cost estimates and augmentation information from TNSPs for projects currently being assessed under the RIT-T, as the projects progress. Because these projects remain uncertain until final funding approval is received, they are modelled as augmentation options in the ISP (that is, they are not assumed to proceed until they become anticipated or committed). AEMO considers that TNSPs are best placed to estimate the cost of these projects. To ensure consistency across regions, AEMO reserves the right

[17] For further information about regulatory treatment of early works, please see the AEMC's final rule determination in September 2024 on bringing early works forward to improve transmission planning, at https://www.aemc.gov.au/rule-changes/bringing-early-works-forward-improve-transmission-planning.

to add offsets to prices advised by TNSPs to ensure uncertainty and risks are applied consistently across investment options.

Table 5 lists the actionable ISP projects identified in the 2024 ISP for which the RIT-T is complete or in progress and will be included for consideration as actionable ISP projects in the 2026 ISP. AEMO may also use updated information in the ISP, for example as included in the latest Transmission Augmentation Information publication.

Table 5 Actionable ISP projects in the 2024 ISP

Project	Responsible TNSP(s)	Section in this report
Sydney Ring South	Transgrid	Section 3.8
VNI West	Transgrid and AEMO (Victorian Planning)	Section 3.11
Mid North South Australia REZ Expansion	ElectraNet	Section 4.4.9
Waddamana to Palmerston transfer capability upgrade	TasNetworks	Section 4.5.3
Project Marinus	TasNetworks and Marinus Link	Section 3.14
Queensland – New South Wales Interconnector (QNI Connect)	Transgrid and Powerlink	Section 3.5

Actionable projects which progress under a jurisdictional framework

Actionable projects which do not undergo the RIT-T are those that are progressing under a jurisdictional framework. The project proponent (a TNSP or a jurisdictional body, as relevant) proceeds through a review process which is unique to the local jurisdiction.

AEMO requests updated cost estimates and augmentation information from project proponents for projects currently progressing through a jurisdictional framework. Because these projects remain uncertain until final funding approval is received, they are modelled as augmentation options in the ISP (that is, they are not assumed to proceed until they become anticipated or committed). AEMO considers that project proponents are best placed to estimate the cost of these projects. To ensure consistency across regions, AEMO reserves the right to add offsets to prices advised by project proponents to ensure uncertainty and risks are applied consistently across investment options.

Table 6 lists actionable projects identified in the 2024 ISP which are progressing under a jurisdictional framework and will be included for consideration as actionable projects in the 2026 ISP. AEMO may also use updated information in the ISP, for example as included in the latest Transmission Augmentation Information publication.

Table 6 Actionable projects progressing under a jurisdictional framework in the 2024 ISP

Project	Actionable framework	Project proponent	Section in this report
Hunter-Central Coast REZ Network Infrastructure Project	NSW[A]	EnergyCo	Section 4.2.9
Sydney Ring North (Hunter Transmission Project)	NSW[A]	EnergyCo	Section 3.8
Gladstone Grid Reinforcement	QLD[B]	Powerlink	Section 3.3
New England REZ Network Infrastructure Project	NSW[A]	EnergyCo	Sections 3.6 and 4.2.2
Queensland SuperGrid South	QLD[B]	Powerlink	Section 3.4

A. These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
B. These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.

Future ISP projects with preparatory activities

Preparatory activities are intended to improve the conceptual design, lead time, location and cost estimates for transmission projects. The ISP may require preparatory activities for some future ISP projects. Future ISP projects are projects which address an identified need, form part of the ODP, and may be actionable ISP projects in the future.

AEMO did not require that TNSPs commence preparatory activities for any of the future ISP projects identified in the 2024 ISP, so no preparatory activities reports will be provided to inform the final 2025 *Electricity Network Options Report*.

AEMO estimates

There are many transmission projects assessed in the ISP where TNSPs and jurisdictional bodies have not developed augmentation options and cost estimates. For these projects, AEMO determines and consults on conceptual augmentation options and cost estimates, including through extensive joint planning with the relevant TNSP.

AEMO uses the latest version of the AEMO Transmission Cost Database[18] to cost the transmission augmentation project options for which cost estimates have not been developed by TNSPs or jurisdictional bodies. Section 2.2.3 provides further information about the update to the AEMO Transmission Cost Database undertaken in preparation for the 2026 ISP.

This report outlines options for transmission augmentation projects. Section 2 lays out the methodology for key conceptual design, project lead time, location and costing matters.

The augmentation options are then provided, split into:

- **flow paths** – the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected network to load centres – see Section 3, and
- **REZs** – the network required to connect renewable generation in areas where cluster of large-scale renewable energy can be developed using economies of scale – see Section 4.

AEMO also applies the Transmission Cost database to estimate generation and storage connection costs, including system strength costs, treatment of offshore resource connections, and connection costs for onshore generators – see Section 6.

1.3 Call for non-network alternatives to transmission options

Non-network options are defined in the NER as a means by which an identified need can be fully or partly addressed other than by a network option. Non-network options include a range of technologies, for example:

- Generation investment (including embedded or large-scale).

[18] Version 3.0 of the AEMO Transmission Cost Database, released May 2025, is at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios/transmission-cost-database . Register to receive it at https://forms.office.com/r/YbmiGc24TP.

- Storage technologies (such as battery storage and pumped hydro).
- Demand response.

AEMO will seek input on and consider non-network options in preparing the 2026 ISP.

As per Section 3.4.3 of the AER's Cost Benefit Analysis (CBA) Guidelines[19], prior to the Draft ISP, AEMO is required to:

- undertake early engagement with non-network proponents to gather information in relation to non-network options, and
- if there are any credible non-network options identified through early engagement and joint planning, but not included in a Transmission Annual Planning Report, include these in its process for selecting development paths.

AEMO must seek proposals for non-network options for actionable ISP projects identified in a Draft ISP.

In the ISP, AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy. Depending on their relative costs and benefits, the capital costs of large network augmentation could be deferred or avoided by delivering a non-network solution.

At this stage, AEMO is seeking information on non-network technologies or proponents so ISP modelling can flag opportunities for competitive non-network investment. To model non-network technologies, AEMO is seeking information on:

- specific non-network concepts and proposals
- the resultant network capacity gained
- cost of the non-network solution, and
- project lead time.

Stakeholders are encouraged to submit non-network alternatives for the options proposed in Section 3 and Section 4 of this Draft 2025 *Electricity Network Options Report*, consistent with the specific information requested above.

1.4 Application of distribution network opportunities in the ISP

To improve consideration of demand-side factors in the ISP, AEMO will publish a demand-side factors statement and will identify the scale of opportunities for distribution network developments consistent with the efficient development of the power system[20]. AEMO will:

1. Undertake close engagement with DNSPs, through an established working group.

[19] AER. *Cost Benefit Analysis Guidelines*, November 2024. At https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[20] AEMC. *Rule determination. National Electricity Amendment (Improving consideration of demand-side factors in the ISP) Rule 2024*, December 2024. At https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp.

2. Consult on its method for assessing the scale of opportunities for distribution network developments through the review of the ISP Methodology[21].
3. Consult on its method for gathering and calculating the scale of distribution network opportunities to facilitate the aggregate operation of forecast CER uptake and other distributed resources (Section 2.12 of this report).
4. Consult on its proposed distribution network data for calculating the scale of opportunities to facilitate the aggregate operation of forecast CER uptake and other distributed resources (Section 5 of this report).
5. Assess distribution network investment for CER and other distributed resources at the sub-regional level of the ISP model as part of preparing the Draft 2026 ISP, and report on outcomes for consultation in a demand side factors statement.
6. Publish a final demand side factors statement within the final 2026 ISP.

AEMO notes that while best endeavours have been made by AEMO and DNSPs to prepare data and an approach for application in the 2026 ISP, this data and modelling is novel and will evolve over successive ISPs.

1.5 2026 ISP development process

Figure 3 shows the ISP process as a whole, and current progress on all elements for the 2026 ISP[22]. In addition to this Draft 2025 *Electricity Network Options Report* consultation, three other consultations that will inform the 2026 ISP are underway:

- **The 2025 IASR[23]** will catalogue the range of inputs, assumptions and scenarios for the 2026 ISP. At the time of publication of this paper, AEMO has received submissions on the Draft 2025 IASR Stage 1 and Stage 2 reports, has hosted a webinar, and will continue to finalise responses to feedback before publishing the final 2025 IASR in July 2025.
- **A review of the ISP Methodology[24]** is considering four key changes to the methodology which sets out how modelling is applied in the ISP and how cost benefit analysis is used in the ISP. The review included an issues paper published in October 2024 with written submissions due in November 2024, and a draft report and Draft ISP Methodology published in May 2025 with written submissions due in April 2025. At the time of publication of this paper, AEMO is considering stakeholder submissions and will continue to finalise responses to feedback before publishing a final report and the ISP Methodology on 25 June 2025.
- **The 2025 *Gas Infrastructure Options Report*** has been newly created as part of the 2025 IASR, to consult on inputs and assumptions used for the gas development projections to be included in the 2026 ISP, consistent with the outcomes of the ISP Review and subsequent changes to the NER and NGR. AEMO has released the Draft 2025 *Gas Infrastructure Options Report* for consultation on the same day as this report, and will consider stakeholder submissions before finalising responses to feedback and publishing a final report in July 2025.

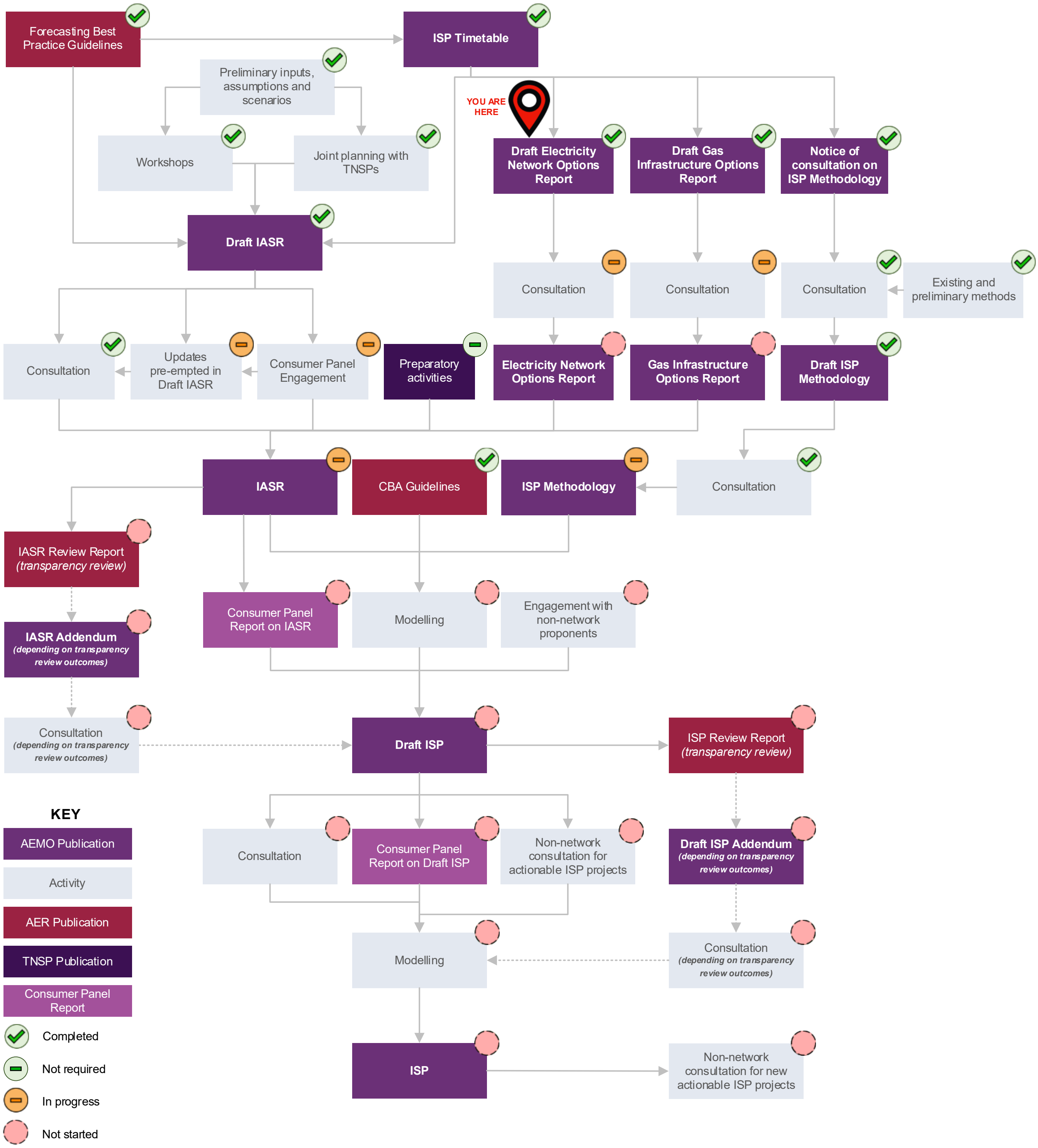
[21] At https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[22] The 2026 ISP Timetable provides more information on the key milestones of the 2026 ISP development process, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

[23] AEMO. 2025-26 Inputs, Assumptions and Scenarios. At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[24] AEMO. ISP Methodology consultation. At https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

Figure 3 Navigating the ISP process



Note: The diagram above has been amended from the version published in the 2026 ISP timetable by adding boxes for the draft and final versions of the "Electricity Network Options Report" and "Gas Infrastructure Options Report" with an additional "Consultation" box for each publication. The IASR will consider transmission and distribution development options and non-network alternatives.

2 Methodology

AEMO assesses conceptual design, project lead time, location, and cost estimates for transmission augmentation options that will be considered in the ISP. AEMO seeks to collaborate with TNSPs and jurisdictional bodies to co-design network options for the ISP. AEMO, TNSPs and jurisdictional bodies have undertaken extensive joint planning to inform the preparation of this report. This section outlines the methodology for assessing these options.

AEMO also includes distribution network opportunities for facilitating the aggregate operation of CER and other distributed resources, including network capabilities and augmentation opportunities, and broad cost rates. AEMO has collaborated closely with DNSPs to inform the preparation of this report, and this section outlines the methodology for preparing these opportunities and their application into the ISP model.

Section 2 outlines the methodology for assessing transmission network augmentation project options and distribution network opportunities:

- Transmission cost estimation framework (Section 2.1).
- AEMO Transmission Cost Database (Section 2.2).
- Review of TNSP cost estimates (Section 2.3).
- Estimating operational expenditure for transmission (Section 2.4).
- Landholder payment schemes for transmission (Section 2.5).
- Economic, social and environmental costs and benefits for transmission (Section 2.6).
- Market impacts on transmission costs (Section 2.7).
- Treatment of concessional finance for transmission projects (Section 2.8).
- Projected changes in transmission infrastructure costs over time (Section 2.9).
- Transmission project lead time (Section 2.10).
- Social licence for transmission projects (Section 2.11).
- Distribution network opportunities (Section 2.12).

2.1 Transmission cost estimation framework

This section outlines the treatment of cost estimate classifications and their application for the ISP, including the approach for incorporating risk.

2.1.1 Treatment of cost estimate classifications for the ISP

This section provides a high-level description of the complex process that is used to develop transmission projects, and relevant generic background on the nature of cost estimation. The content represents AEMO's understanding of the typical stages of project development and estimation used by TNSPs and other jurisdictional planning bodies in the NEM[25], noting that this may vary for individual TNSPs. The content is not prescriptive, and stakeholders are referred to the AER Cost Benefit Analysis Guidelines[26] and the Regulatory Investment Test for Transmission Application Guidelines[27] for more information, as well as relevant government websites in cases where the RIT-T is not applied[28].

Cost estimates progress from a very early stage with little design or information known (least accurate) to a fully costed and engineered estimate (most accurate).

In the early stages, allowances are used to account for the fact that the work scope is not well defined, project approvals have not yet been obtained, and component costs may not be market-tested. Because these allowances are uncertain, the accuracy of early estimates is low. As projects mature and the scope of works is further defined, more of the cost is assigned to the base estimate, reducing the size of allowances for risks and uncertainties, and improving the accuracy.

The Association for Advancement of Cost Engineering (AACE) International classification system is commonly used in many industries for defining the level of accuracy of a cost estimate, based on the amount of design work that has been done[29]. This system defines a series of 'classes' of estimates, ranging from Class 5 (least accurate) to Class 1 (most accurate). AEMO has followed the framework of the AACE International guideline for its cost estimate methodology to classify cost estimates, and defined sub-categories to reflect the range of estimates and accuracies that are available within the Australian regulated electricity sector. These are defined as follows:

- Class 5b – concept level scoping with no site-specific review or TNSP input.
- Class 5a – screening level scoping including high level site-specific review and TNSP input.

Further detail on the associated accuracies of these classes is provided in Section 2.2.2.

Figure 4 illustrates how the definition of a single parameter within an estimate (using the example of transmission overhead line length) is progressed as a project matures from a Class 5b to Class 2 or 1 within the framework. Studies in the early stages (Class 5b/5a/4/3) are usually confined to desktop analysis, with field work only introduced from Class 3 or later in the project development.

It is important to note that this process does not rely on a linear maturation of the scope of works; rather, Class 5b (the earliest stage) relies on significantly fewer inputs than what would be required for Class 4 or Class 3. It must also be noted that accuracy bands are ascribed on the basis of the whole project, not as individual elements.

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[25] Please note that while descriptions in this section may be broadly aligned with the planning approach applied by jurisdictional bodies with transmission network planning functions (for example EnergyCo and VicGrid), this section is referring specifically to the RIT-T process applicable for TNSPs in the NEM, rather than the jurisdictional regulatory frameworks which deliver transmission projects outside of the RIT-T process.

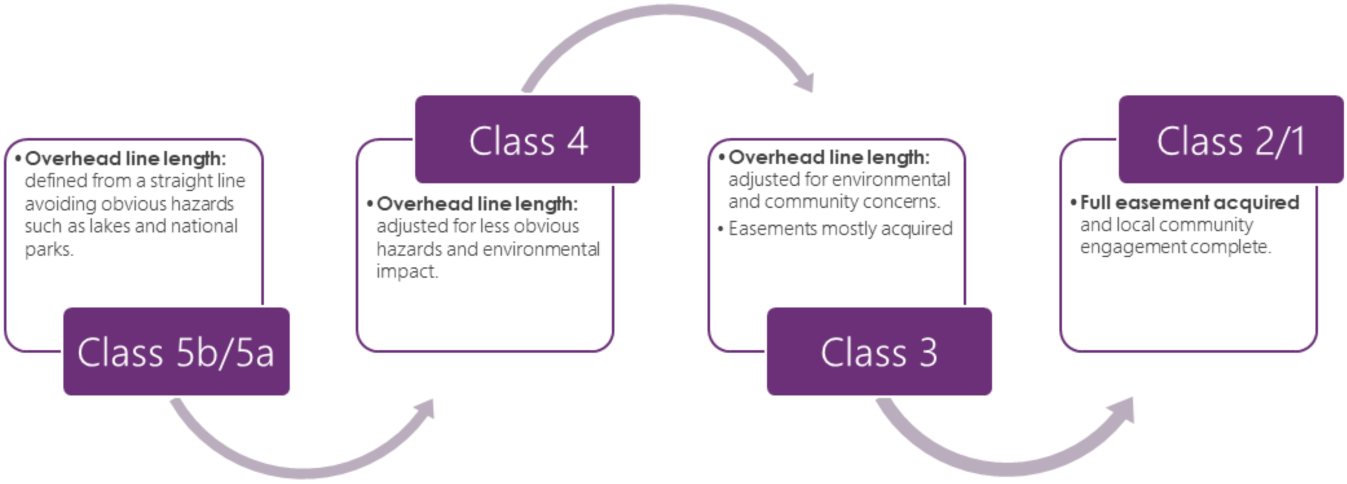
[26] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[27] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20RIT-T%20application%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[28] Examples of jurisdictions where alternate transmission network planning frameworks apply, rather than the RIT-T, include New South Wales and Victoria. In New South Wales, EnergyCo delivers the Electricity Infrastructure Roadmap under the *Electricity Infrastructure Investment Act 2020* (NSW) (more information is at https://www.energyco.nsw.gov.au/). In Victoria, VicGrid delivers the Victorian Transmission Investment Framework under the *National Electricity (Victoria) Act 2005* (Vic) (more information is at https://www.energy.vic.gov.au/renewable-energy/vicgrid).

[29] AACE International. *Recommended Practice No. 17R-97 Cost Estimate Classification System*, Rev. August 2020, and *Recommended Practice No. 96R-18 Cost Estimate Classification System – As applied in engineering, procurement, and construction for the power transmission line infrastructure industries*, Rev. August 2020. Accessed under licensing arrangements via https://web.aacei.org/.

Figure 4 Design progress with project maturity – example showing how overhead line length assumption changes



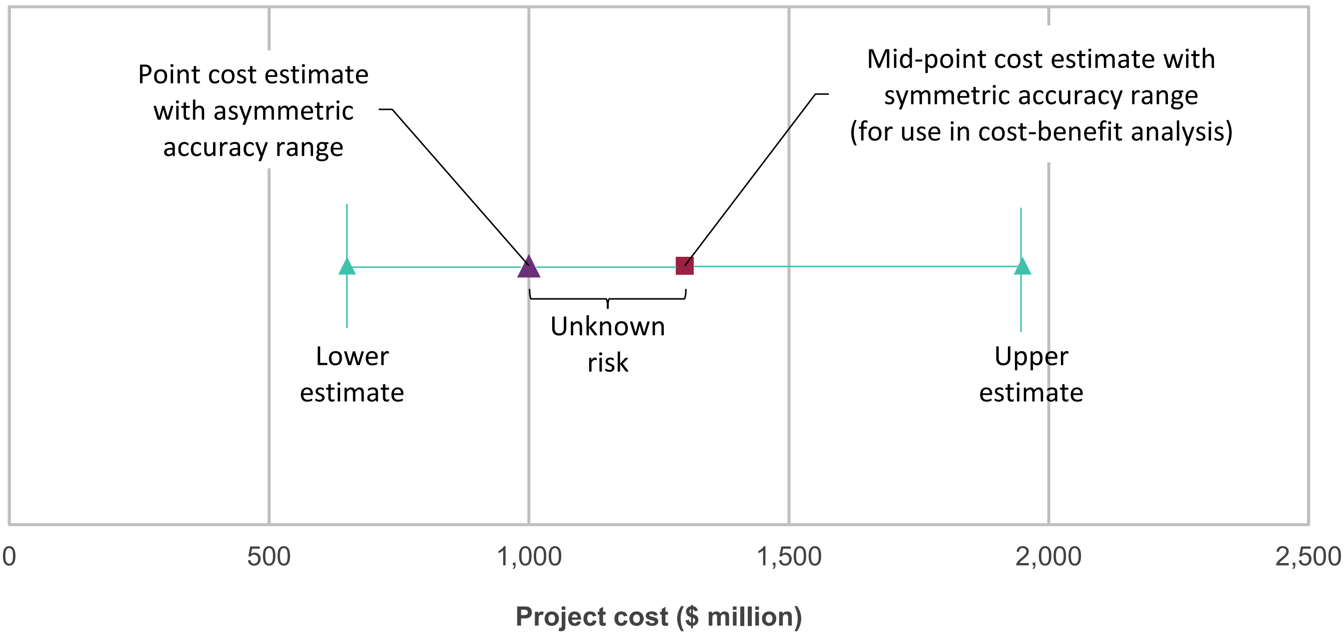
Deviation from the AACE cost estimation framework

AEMO acknowledges that its approach to applying cost estimation in the ISP may deviate from the AACE framework in two superficial ways:

- **Splitting class 5 into two categories** – the AACE framework for power transmission line infrastructure sets out a range of accuracy bands for all estimate classes. Because the ISP includes a wide range of Class 5 estimates, AEMO has decided to categorise estimates as “Class 5a” or “Class 5b” as a succinct way to reflect whether the estimate is at the upper bound or lower bound of the accuracy range.
- **Presentation of symmetric accuracy bands** – the AACE framework reflects that cost estimates typically have an asymmetrical risk profile (for example, a project might have a -50% to +100% accuracy range). While AEMO agrees that cost estimates have an asymmetric risk profile, the AACE framework presents an approach for estimating costs but does not specify how the uncertainty range should be applied in a cost-benefit analysis.

In the ISP, AEMO uses the AACE framework to determine a point cost estimate with an asymmetrical uncertainty range for a cost estimate, but then applies an unknown risk factor to uplift the point cost estimate while leaving the lower and upper ends of the accuracy range constant. The result of this increase from an asymmetric point cost to a mid-point cost is that the resulting uncertainty range is symmetric. Adding this ‘contingency’ to the point estimate does not affect estimate accuracy; this is shown in **Figure 5** below. This approach closely aligns with an example in AACE documentation, although no guidance is provided on how accuracy bands should be articulated following the addition of a contingency allowance.

Figure 5 Addition of unknown risk to determine a mid-point cost estimate for cost-benefit analysis



2.1.2 Application to the ISP

The development of the Transmission Cost Database has helped refine AEMO's approach to cost estimation, and informed the definition of the work needed across each step of development.

Table 7 shows the current steps for ISP projects and outlines the planning and development works that typically take place at each step. The indicative cost estimate class levels shown here reflect AEMO's current understanding of levels typically used at each step, which may vary across TNSPs and jurisdictional bodies, and across projects. The AER Cost Benefit Analysis Guidelines[30] and RIT-T Application Guidelines[31] outline the expectations for RIT-T proponents, however they do not require a specific class level for cost estimates at any stage, as estimate accuracy achieved at each step will depend on the nature of the project.

Table 7 Indicative ISP project development step

Step	Future ISP projects identification (by AEMO)	Preparatory activities for future projects	Project Assessment Draft Report (PADR)	Project Assessment Conclusions Report (PACR)	Contingent Project Application (CPA)[A]
Description	• Identification of future projects to include in the ISP • High-level assessment of potential costs/ benefits to determine whether project has net benefits	• More detailed analysis of project options to determine provisional preferred option, and refine time, cost and technical scopes	• Comparison of credible options to identify a draft preferred option	• Final report on the comparison of credible options to determine the preferred option, taking into account submissions received on PADR	• Final application to AER for revenue adjustment to reflect costs of the project

[30] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[31] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20RIT-T%20application%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

Step	Future ISP projects identification (by AEMO)	Preparatory activities for future projects	Project Assessment Draft Report (PADR)	Project Assessment Conclusions Report (PACR)	Contingent Project Application (CPA) [A]
Cost estimates informed by	• High-level technical specifications developed (e.g. voltage/capacity and conceptual single line diagrams) • Class 5b: Network path identified at concept level with no site-specific review or TNSP input • Class 5a: Network path identified at screening level with some site-specific review and TNSP input	• Technical specifications refined, relevant network studies underway • For significant projects a non-committal budget (guide) estimate from appropriate contractors/ suppliers may be sought • Desktop geotechnical/ ecology/heritage/ planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Stakeholder engagement plan developed • Credible alignment path identified, avoiding significant known risks and environmental sensitivities • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Technical specifications refined, relevant network studies substantially complete • Concept tower and substation design further refined • For significant projects a non-committal budget (guide) estimate from appropriate contractors/ suppliers may be sought • Desktop geotechnical/ ecology/heritage/ planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Credible network option identified based on geotechnical/ ecology/heritage and tenure desktop planning and network studies • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Technical specifications completed • For significant projects a non-committal budget (guide) estimate from appropriate contractors/ suppliers may be sought • Desktop geotechnical/ ecology/heritage/ planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Major landowners identified • Credible network option further refined • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Detailed technical specifications completed for market costing • Market engagement complete, procurement substantially progressed • Detailed geotechnical investigations substantially progressed • Procurement of options over easement commenced, initial consultation with landowners substantially complete • Alignment progressing to finalisation apart from micrositing issues • Biodiversity offset liability determined and strategy finalised • Ecology/heritage studies substantially progressed • Planning approval commenced • Corporate cost budget finalised
Approximate class	Class 5	Class 4 to 5	Class 4 to 5	Class 3 to 5	Class 2 to 4[B]
Cost source for ISP modelling	Transmission Cost Database	Primary cost estimate from TNSPs, cross check with Transmission Cost Database	Primary cost estimate from TNSPs, cross check with Transmission Cost Database	Primary cost estimate from TNSPs, cross check with Transmission Cost Database	Not required for committed projects

A. Regulations differ in Victoria, where there is no CPA stage following the RIT-T.
B. Unknown risk allowances are intended to be used in the Transmission Cost Database for projects at RIT-T or earlier stages. The AER's guidance note on the regulation of actionable ISP projects expects that unknown risks should not be included at the CPA stage, and that TNSPs should undertake activities to identify all risks prior to submission of the CPA.

AEMO produces cost estimates for future ISP projects using the Transmission Cost Database, which was initially designed to produce Class 5a estimates from screening level scope definition. The Transmission Cost Database has been updated to produce both Class 5a and Class 5b estimates. Class 5b applies unknown risk factors that are twice that of the Class 5a unknown risk factors. This update was driven by confidential project cost data which provided evidence to support this approach, and has been confirmed through the 2025 update of the

Transmission Cost Database. This replaces the previous approach which was to apply a factor to the output of the database to calculate the Class 5b total expected cost.

As the projects move into preparatory activities or become actionable, TNSPs typically produce Class 5a or 4 estimates as their scope is further refined. In some instances, projects will be delivered in stages, which allows early project stages to be funded and progressed prior to late project stages. This approach allows time for the full project estimate to be further developed before funding is allocated.

While the primary use of the Transmission Cost Database is to produce Class 5b or 5a estimates for future ISP projects, it will also be used to cross-check estimates received from TNSPs, to ensure consistency. This process is discussed further in Section 2.3.

AEMO includes all committed and anticipated projects[32] in all future states of the world, in accordance with the AER's Cost Benefit Analysis (CBA) Guidelines[33]. This means the capital cost and benefits for committed and anticipated projects are not evaluated as part of the ISP modelling process (similar to the capital cost of existing generation and transmission) because the projects are under construction, or are committed or anticipated to be developed. As such, the ISP does not evaluate the merits of these previous investment decisions. These projects are all included in AEMO's Draft 2025 Inputs and Assumptions workbook[34]. The latest status and details of these projects are updated on AEMO's Generator Information Page[35] and Transmission Augmentation Information Page[36]. Committed and anticipated projects are therefore not described in detail in this report.

2.2 AEMO Transmission Cost Database

The Transmission Cost Database was first produced in response to stakeholder feedback on the 2020 ISP. AEMO commissioned the Transmission Cost Database to provide increased transparency and accuracy of estimates of costs of future ISP projects, thereby enhancing the ISP outcomes and increasing stakeholder confidence in the estimates. Regular updates of the Transmission Cost Database are required to ensure the currency of the future ISP project cost estimates, and to incorporate the experience of current RIT-T projects, AER contingent project decisions, and network revenue determinations into these updates. Section 2.2.3 provides information about the 2025 update to the Transmission Cost Database[37].

[32] Committed transmission augmentation projects meet five criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment, and necessary financing arrangements. Anticipated projects are in the process of meeting at least three of the criteria. Details about the criteria are provided in AEMO's Transmission Augmentation Information publication, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[33] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[34] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[35] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

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

[37] AEMO. Transmission Cost Database, version 3.0. Available by completing a request form at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios/transmission-cost-database.

The Transmission Cost Database is comprised of a Cost and Risk Data workbook, containing all the fundamental components used to compile a project cost estimate, and a cost estimation tool with an interactive ‘Dashboard’ containing algorithms that processes the user inputs and selection choices.

As outlined in Section 2.2.2, the Transmission Cost Database is intended for use by AEMO to generate Class 5a/b cost estimates for conceptual future ISP projects (or Class 4 in limited circumstances). It is not intended to produce more advanced estimates, as the breakdown of components is not sufficiently detailed. The Transmission Cost Database has been published to allow stakeholders to access the detail within the cost estimates, when assessing and providing feedback during the consultation.

This Section 2.2 provides an overview of the AEMO Transmission Cost Database:

- Cost estimate components and treatment of risk (Section 2.2.1)
- Cost estimate progression (Section 2.2.2), and
- 2025 update of the AEMO Transmission Cost Database (Section 2.2.3), as well as a detailed report from GHD provided as an attachment to this report[38].

2.2.1 Cost estimate components and treatment of risk

For the purposes of the Transmission Cost Database, cost estimates are broken down into several components, which are described in the following sections:

- building blocks and baseline cost
- adjustments for project specific attributes
- risk allowance, and
- indirect costs.

Building blocks and baseline cost

Cost estimates are typically initiated by defining the quantities of certain ‘building blocks’ or plant/equipment items and multiplying these by the unit cost per item (such as $/km of overhead line or cost of a 500/330 kilovolt [kV] transformer). The list of building blocks required is developed by defining the scope of work required to deliver the project’s objectives, and is the outcome of engineering design. The sum of the building block costs is the baseline cost.

Adjustments for project specific attributes

Building block costs will vary depending on many project-specific variables. It is therefore necessary to adjust the basic unit costs to take account of these factors. Building block adjustment factors are built into the Transmission Cost Database for selection by the user. They are based on past project data, and include the complexity of the project, its location, the type of terrain involved, and environmental factors. For large projects where a certain factor may change over the length of a transmission line, the project is broken into ‘network elements’ which can fit within a given selection. The selected adjustment factors are made transparent to stakeholders by listing them

[38] At https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report.

in each project table in Sections 3 and 4 of this report. In addition, the numerical and percentage value of each adjustment factor is presented in the detailed output file for each project[39].

Risk allowance

As estimates become more accurate, the quantities (scope) typically increase. Unit costs also tend to increase with design definition. The Transmission Cost Database accounts for these increases by defining two risk types:

- Known risks – where risks are identified but the ultimate value of the risk is not known.
- Unknown risks – where the risk has not been identified but industry experience shows that in the course of major projects these can occur. With benefit of hindsight, such risks are not considered fully at the time of estimate preparation.

Indirect costs

Indirect costs represent the project owner's internal costs. They represent all costs not covered by the contractors or suppliers.

2.2.2 Cost estimate progression

Figure 6 illustrates conceptually the cost structure used by AEMO. The relative heights of the bars in this figure are indicative and will vary according to individual project details. The adjusted baseline costs are shown as "known costs". Known risk allowances, unknown risk allowances and indirect costs are added to the known costs to form the expected project cost. The known costs increasingly become a larger component of the total cost estimate, while risk allowances decrease as the design progresses. The expectation is that unknown risks will reduce to near zero as the project advances through delivery to completion.

Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. With this cost estimation approach, a class 5b estimate with an accuracy range of ±50% might reasonably cost 150% of the original estimate once delivered in full. Further, because there is an 80% likelihood of the project cost falling within this range, there is also a 20% likelihood that the cost does not fall within this range. Finally, material changes to the scope of a project, beyond those covered by known and unknown risks, can result in further cost changes that are not reflected by these ranges.

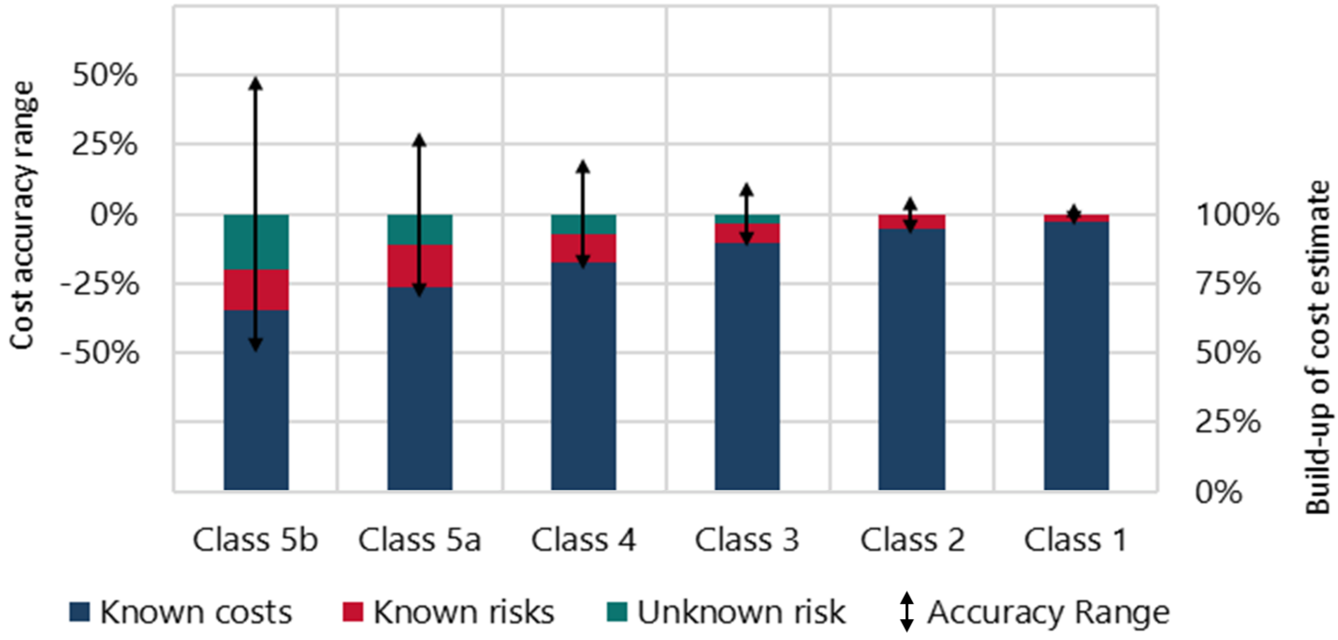
Unknown risk allowances are intended to be used in the Transmission Cost Database for projects at RIT-T or earlier stages. The AER's guidance note on the regulation of actionable ISP projects states an expectation that TNSPs undertake activities that may reveal project risks and reduce uncertainty, including for unknown risks where it is not possible to assign probability to a risk, prior to submitting a contingent project application (CPA)[40]. This should help minimise unknown risks considered at the CPA stage, recognising that staging projects or CPAs may also help TNSPs to identify and quantify project risks and reduce uncertainty. This may or may not be possible for projects depending on the scope; for example, if involving a transmission line, the route is unlikely to

[39] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/draft-transmission-cost-estimate-calculations.

[40] AER. *Guidance note. Regulation of actionable ISP projects*, March 2021. At https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects.

be able to be determined to the required level at an early stage of the project. This is one reason a project may be delivered in stages, allowing early project stages to be funded and progressed prior to late project stages as discussed earlier.

Figure 6 Cost estimate summary breakdown from Class 5b to Class 1



It may be helpful to note that TNSPs do not receive approval for revenue recovery for a project until the CPA is approved by the AER (including in the case of cost recovery for early works[41]), and therefore the estimates produced for ISP modelling at earlier stages will have broader accuracy bands than that required for the CPA.

Class 5a/5b Definition

As discussed in Section 2.1, AEMO introduced sub-categories within Class 5 to transparently reflect the range of estimates and accuracies that are available within the Australian regulated electricity sector. These are defined in **Table 8**, with further explanation below.

Table 8 Class 5 estimate sub-categories

Class	Definition	Unknown risk allowance[A]	Accuracy[B]
Class 5b	Concept level scoping with no site-specific review or TNSP input	Up to 30%	±50%
Class 5a	Screening level scoping including high level site-specific review and TNSP input	Up to 15%	±30%

A. Unknown risk allowance defined as a percentage of the total network element cost (which does not include indirect costs).
B. Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

[41] In September 2024, the AEMC made a rule change determination to provide certainty on cost recovery for early works, which are activities such as (but not limited to) stakeholder engagement, corridor assessment, procurement of equipment and assets with long lead times, preparation of jurisdictional planning approvals and easement acquisition. Further information is at https://www.aemc.gov.au/rule-changes/bringing-early-works-forward-improve-transmission-planning.

The AACE International methodology typically contains accuracy bands which are skewed to the positive side, reflecting higher likelihood of cost increases than decreases as the estimate progresses. The Transmission Cost Database has been designed to include an average allowance for unknown risks which offsets the adjusted building block estimate, such that the 'total expected cost' resulting from the Transmission Cost Database can be used as the mid-point of a symmetrical accuracy band for ISP modelling purposes – see Section 2.1.1 for more information.

In this approach, the higher up-side risk of cost increases is reflected directly in a higher cost estimate with symmetrical accuracy bands, rather than in skewed accuracy bands. In Figure 6 above, if the up to 30% unknown risk factor were omitted from the Class 5b estimate, the upper and lower bounds of the estimate would be more aligned with the AACE's asymmetrical accuracy band for a Class 5 estimate.

The Transmission Cost Database is currently designed to produce Class 5a and Class 5b estimates. The accuracy of the Class 5a estimates produced by the Transmission Cost Database is approximately ±30%, with an unknown risk allowance of up to 15%. This allowance was first determined by GHD for the initial 2021 Transmission Cost Database using statistical analysis of current major transmission network projects as they progressed from screening stage scope definition to CPA. For the 2025 Transmission Cost Database, GHD reviewed this unknown risk allowance against present-day market cost information, following increased transmission network planning and delivery activity in the NEM, ultimately finding that the unknown risk allowances remain appropriate for continued application[42].

Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands. The accuracy of the Class 5b estimate produced by the Transmission Cost Database is estimated to be ±50%, with an average unknown risk allowance of up to 30%. Importantly, AEMO also escalates future project costs on top of these estimates. This way, it can also help quantify some of the additional risks to the project estimate.

Transmission Cost Database detailed structure and content

The Transmission Cost Database consists of two separate Excel files:

- A Cost and Risk Data workbook containing all the fundamental components used to compile a project cost estimate.
- A cost estimation tool with interactive 'Dashboard' containing algorithms that processes the user inputs and selection choices.

To estimate costs, the user selects plant items from lists of categories and sub-categories, and applies appropriate adjustment factors and risks. The selection choices are processed by the algorithms within the estimation tool, producing the expected project cost.

[42] The up to 30% uplift to account for unknown risk in Class 5b estimates is based on the best evidence available to AEMO at the time of publishing the Draft 2025 *Electricity Network Options Report*. The value is based on analysis of 22 transmission network projects in 2021, and was verified based on analysis of 31 transmission network projects and plant cost component of various asset subcategories in 2025. AEMO engaged GHD to conduct this analysis in both cases, which included using present-day market cost information gathered from all TNSPs in the NEM as well as information from five original equipment manufacturers (OEMs).

The Transmission Cost Database cost estimation tool is available for stakeholder use and contains a complete copy of the Cost and Risk Data. A detailed user manual is also provided. These files, along with instructions on how to download and run the tool, are available on the AEMO website[43]. Full details of the Transmission Cost Database construction including cost and risk data sources are given in GHD's 2021 report on the original creation of the Transmission Cost Database[44], with further information on updates available in Mott Macdonald's report on the 2023 update of the Transmission Cost Database[45], and GHD's report on the 2025 update of the Transmission Cost Database[46].

2.2.3 Update of the AEMO Transmission Cost Database

AEMO's Transmission Cost Database is a tool which allows AEMO to develop cost estimates for future ISP network augmentation options and can be used by external parties to develop conceptual cost estimates for potential transmission augmentations. AEMO updates the Transmission Cost Database to ensure that the ISP is prepared using up to date transmission cost estimate information. An update may include updating cost estimates for individual equipment or cost component building blocks, revision of attributes and risk allowances, and inclusion of additional selections to ensure the tool remains relevant in the changing technology landscape.

This section explains the 2025 update undertaken by GHD for the 2026 ISP. This update is open for consultation and stakeholder feedback as part of this *Draft 2025 Electricity Network Options Report.*

In 2024, AEMO engaged consultants GHD (in collaboration with Amplitude Consultants) to deliver a suite of updates to the Transmission Cost Database. These updates improved the alignment of the Transmission Cost Database with TNSPs' best practice in conceptual cost estimates for transmission infrastructure, and improved the accuracy of the tool through review of the project attribute and risk factors. The work included surveys and benchmarking exercises with cost estimation experts in the NEM TNSPs and jurisdictional planning bodies to obtain accurate and market-reflective cost estimate data. As noted by GHD, "The considerable number of transmission projects currently planned or underway by various TNSPs across the NEM allowed for a comprehensive cost information update across a wide range of assets" – an opportunity that was not as extensively available in previous versions of the database.

The updated Transmission Cost Database is provided alongside this Draft 2025 *Electricity Network Options Report,* as well as a GHD report detailing the update. AEMO seeks stakeholders' views on the updated database[47]. The updated 2025 Transmission Cost Database has been used to prepare the draft cost estimates for future projects in this report (except in cases where the project proponent is better placed to provide an estimate). The

[43] The 2023 Transmission Cost Database, version 2.0 as applied for the 2024 ISP, is at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database. The associated user manual is at the same site. This report, the Draft 2025 *Electricity Network Options Report,* applies the updated 2025 Transmission Cost Database, version 3.0, which is the subject of consultation alongside this report and can be requested by stakeholders via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios/transmission-cost-database.

[44] GHD. *Transmission Cost Database – GHD Report*, May 2021. At https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

[45] Mott MacDonald. *Transmission Cost Database Update Final Report*, July 2023. At https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[46] GHD. *GHD 2025 Transmission Cost Database update report*, April 2025. At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/ghd-2025-transmission-cost-database-update-final-report.

[47] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios/transmission-cost-database.

updated Transmission Cost Database will be finalised, including with reference to stakeholder feedback, in time to finalise the transmission project inputs for the 2026 ISP in July 2025.

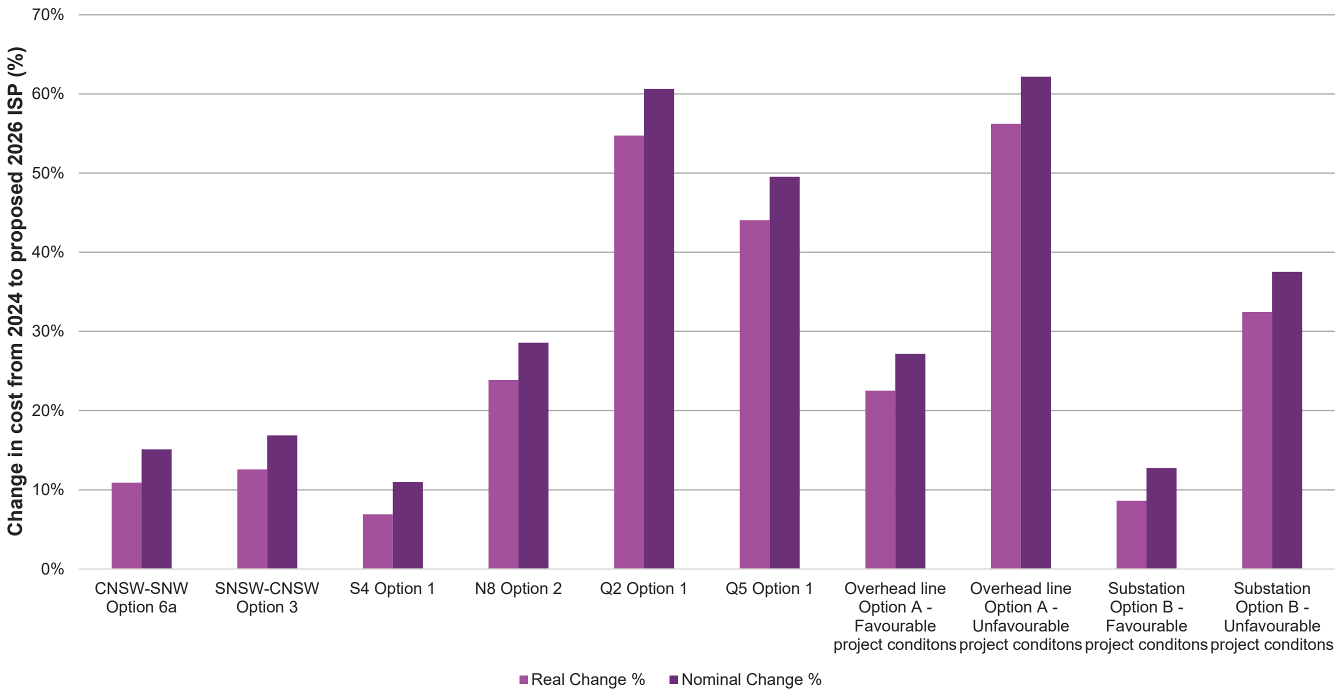
An important result of this update was that project cost estimates produced using the updated Transmission Cost Database were, dependent on scope, approximately 25% to 55% higher (in real terms) for overhead lines than those in the 2023 update, and approximately 10% to 35% higher (in real terms) for substation projects.

TNSPs and other jurisdictional planning bodies have advised AEMO that the recently observed real cost increases in tendering processes and project delivery which are informing this update to the Transmission Cost Database are primarily driven by:

- **sustained supply chain pressures** on materials, equipment and workforce
- **market competition** driven by a high number of concurrent projects under development in the NEM
- **project complexity**, including an increased number of projects planned for remote areas
- **social licence** and additional community and landholder engagement along proposed transmission line routes, and
- **additional contracting costs** to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

Figure 7 shows examples of changes in AEMO cost estimates and compares projects with identical scopes between the 2024 ISP values and the proposed 2026 ISP values.

Figure 7 Change in AEMO cost estimates for comparable projects between 2024 ISP and proposed 2026 ISP



The cost estimates for the 2024 ISP were prepared using the 2023 Transmission Cost Database and adjusted for inflation, and the proposed 2026 ISP cost estimates were prepared using the proposed updates to the 2025

Transmission Cost Database. Four generic overhead line and substation projects[48], studied by GHD, have been included in this figure as many project scopes have changed since the 2024 ISP.

Table 9 summarises key updates made in the 2025 Transmission Cost Database, and a reference for where further detail can be found in GHD's accompanying report.

Table 9 Key updates made in the 2025 Transmission Cost Database

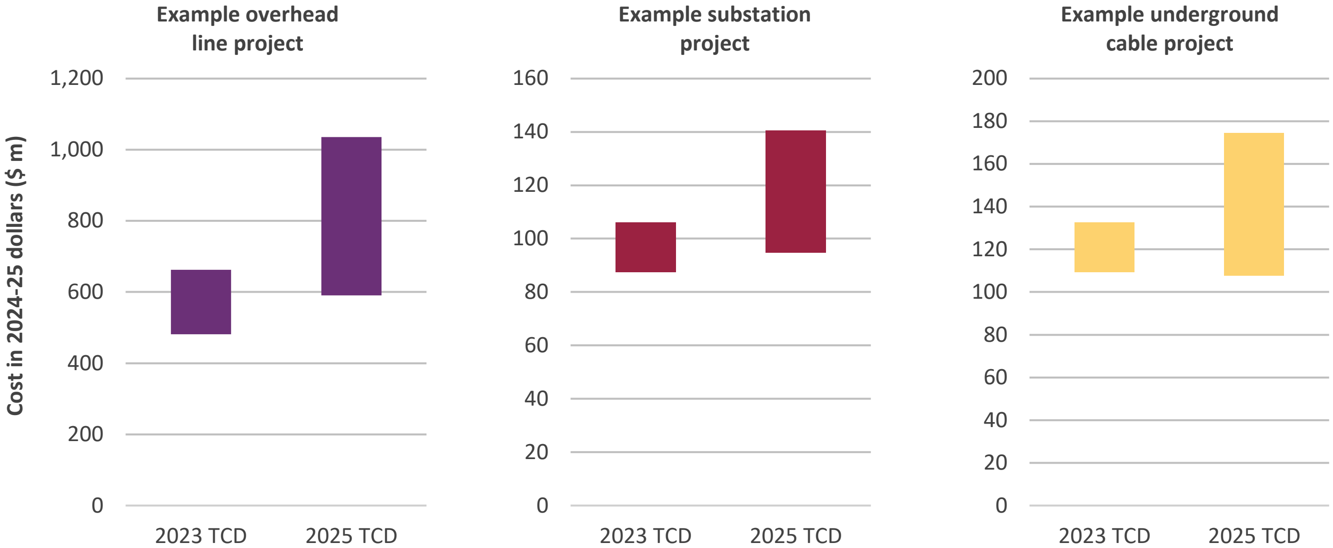
Key update	Outcomes and implications	GHD report reference
Represent present-day market cost information Marked increases in tendering results and delivery costs for transmission projects have been observed within the last 12 months. AEMO has decided to represent these costs in the Transmission Cost Database through application of project attribute factors – users can select 'tight' market conditions in the tool, and observe associated cost uplifts reflecting tight labour, workforce and supply chain conditions.	The proposed updated 2025 Transmission Cost Database can be used to reflect tight market conditions similar to those recently observed in the NEM through careful selection of project attributes. For this Draft 2025 *Electricity Network Options Report*, AEMO has used these selections for tight market conditions for any project options associated with project needs identified before 2024 in the *Step Change* scenario in the 2024 ISP ODP. AEMO considers that this selection reflects the likely tight market conditions that will occur during the 2020s while a high volume of transmission network project options are progressed for delivery. AEMO considers it appropriate to reserve the ability to update cost estimates using these settings within the ISP assessment process, so that if additional projects are seen to be needed within the high market activity period their cost estimates can be adjusted upwards accordingly.	Section 4 'Benchmarking'.
Revise the baseline estimate for biodiversity offset costs GHD undertook a comprehensive review of environmental biodiversity offset costs for all NEM jurisdictions as part of delivering the 2025 Transmission Cost Database update. Users can select 'BAU' for the biodiversity offset cost project attribute in order to reflect the updated and higher cost estimates that are being observed through recent project delivery in the NEM.	The BAU setting for biodiversity offset costs in the tool will now result in higher cost estimates than the previous Transmission Cost Database. As a result, the separate but related 'environmental sensitivity' project attribute factor should be applied prudently, to avoid inappropriately high cost estimates – that is, unless there is a known local environmental sensitivity, users should consider a 'low' environmental sensitivity setting for typical project cost estimates.	Section 2.1.2 'Update to Environmental offset costs component within the baseline estimate'. Section 5.1 'Observations of Change'.
Incorporate closer community and stakeholder engagement needs TNSPs and jurisdictional planning bodies are increasingly reflecting the need to understand and incorporate social licence considerations in their project delivery, with attendant costs to ensure appropriate community and stakeholder engagement is completed.	Cost changes have been reflected in the indirect cost components in the TCD tool, based on survey response data and discussion with TNSPs.	Section 5.1 'Observations of Change'.

[48] 'Overhead line Option A' is a generic 100 km transmission line project consisting of HVAC 500 kV double circuit steel towers, 'quad orange' overhead line, located within southern New South Wales with greenfield work. Favourable project condition settings applied to Overhead Option A: flat, scrubby terrain in a regional location, with no environmentally sensitive areas and low offset risk; excess market capacity for delivery; BAU project complexity; and low geotechnical risk. Unfavourable project condition settings applied to Overhead Option A: mountainous, grazing terrain in a remote location, with 50% environmentally sensitive areas and high offset risk; tight market capacity for delivery; highly complex project complexity; and high geotechnical risk. 'Substation Option B' is a generic substation project consisting of two 330/132 kV transformers and one reactor, 'breaker-and-half' arrangement with air-insulated switchgear switch bays, located in within southern New South Wales with greenfield work. Favourable project condition settings applied to Substation Option B: developed, urban location, with no environmentally sensitive areas and low offset risk; excess capacity market for delivery; BAU project complexity; and low geotechnical risk. Unfavourable project condition settings applied to Substation Option B: a remote location used for grazing, with 50% environmentally sensitive areas and high offset risk; tight market capacity for delivery; highly complex project complexity; and high geotechnical risk.

Key update	Outcomes and implications	GHD report reference
Comprehensive update of high voltage direct current (HDVC) cost estimates Local NEM examples for HVDC transmission projects are sparse, and limited data has been available for previous updates of the tool. In this update, GHD's collaborators Amplitude Consultants were able to provide an uplift of HVDC asset treatment in the tool.	HVDC cost estimates in the updated 2025 Transmission Cost Database are on average markedly higher than previous database costs, due to the uplift in examples prepared and applied for this update, including with reference to both international and local projects.	Section 5.2 'Quantum of change'. Section 2.1 'Update to asset building blocks.'
Change in overhead lines baseline estimate to be baselined for regional Based on survey responses for the 2025 TCD update, most projects were regional projects. Therefore, GHD has updated the overhead baseline estimate for regional location rather than urban to reflect the present market cost projects.	The 'regional' option for location distance factor attribute in the updated TCD correspond to the new baseline estimate and user can adjust this setting by selecting urban or remote options as required and based on project specific.	Section 2.2 'Update to Project Attribute Factors'.
Comparison between 2025 Transmission Cost Database and 2023 Transmission Cost Database cost estimates To bring through the marked market shifts observed for recent transmission projects in the NEM, the updated Transmission Cost Database has used different allocation of costs between building blocks, network attributes and risks.	Transmission Cost Database users should take care when comparing break-downs of 2023 Transmission Cost Database and 2025 Transmission Cost Database cost estimates at the building block level, as the quantum of change will not be clearly observable through comparison of building blocks alone. Rather, a full estimate build-up including network attributes and risks is required to do the comparison.	Section 5.2 'Quantum of change'.
Other application matters GHD's report summarises some smaller changes and outstanding issues for resolution which should be kept in mind when using the updated tool.	Care needs to be taken when using the following components of the tool, with further information provided in GHD's tool: • Indirect project costs. • Synchronous condenser costs. • High-temperature low-sag conductors.	

Figure 8 shows the impact of the market activity settings that have been used to reflect recently observed project cost increases into the updated Transmission Cost Database.

Figure 8 Market activity impacts on project cost estimates in the updated Transmission Cost Database



Note: The lower and upper bounds of each bar represent the cost of an example project, estimated using the 2023 or 2025 TCD, when delivered under favourable and unfavourable conditions respectively (reflected through the settings selected in the TCD).

Consultation questions

1. Do stakeholders agree with the approach taken to reflect recently observed transmission market cost increases in the updated Transmission Cost Database? Do the updated Transmission Cost Database and subsequent cost estimate updates in this report reflect stakeholders' market observations in the NEM?
2. What feedback do stakeholders have about any further work required to support finalising the updated Transmission Cost Database?

2.3 Review of TNSP cost estimates

AEMO will receive project cost estimates from TNSPs for active projects before the release of the final *Electricity Network Options Report* and will provide a review of outcomes in this section of the final report. The purpose of this section is to outline AEMO's approach to reviewing cost estimates provided by TNSPs such that they are complete and consistent, and to validate that AEMO's transmission cost estimation process is reasonable.

AEMO has broadly adopted the AACE standard for the ISP. TNSPs each have their own project cost estimation process that has evolved through the development of their respective transmission project portfolios.

A number of typical project characteristics influence these processes, including:

- the technical scope of projects
  - inclusion of transmission lines, station works or cabling
  - degree of risk definition throughout the maturity of each project
- the degree of information available at the earliest stage of each project, and
- recent experience in procuring sites, land, and easement corridors.

2.3.1 Objectives

AEMO will engage with each TNSP to establish a process to ensure cost estimates are aligned across all projects in AEMO's ISP modelling. The objectives of this engagement will be to:

- improve transparency of how TNSPs develop estimates for projects, including the different stages of cost estimation, inclusion of risk allowances, and accuracy that is achieved at each stage
- develop a common definition of work required to meet each estimate class for transmission projects
- develop a process to align TNSP estimates and enable a consistent approach for inclusion of risk, and
- validate that AEMO's transmission cost estimation process is reasonable.

2.3.2 Checklist development

AEMO has previously engaged with the AER and TNSPs to develop a checklist which reflects various aspects of a project at differences stages of maturity.

For example, one indicator of the amount of design that has been completed on a project is the level of documentation that has been prepared. This aspect forms one line on the checklist; 'Level of Documentation' can be described as:

- Class 5a/b – conceptual single line diagram
- Class 4 – detailed single line diagram, or
- Class 3/2/1 – 'For Construction' electrical and civil drawings.

This engagement process focused on discussions with TNSPs about cost estimation processes, project stages, and stage definitions. The resulting checklist is shown in Appendix A1, and was used to approximate the class of each estimate that was provided by TNSPs.

2.3.3 Review and adjustment process

Estimates that will be received from TNSPs will be reviewed in accordance with this three-stage cost classification process:

1. Classification and preliminary screening of cost estimates:
   a) The TNSP provides completed checklist responses for each project option (ahead of providing cost estimate).
   b) AEMO will approximate the class of the estimate for that project option. This will be done by reviewing the set of TNSP responses against the AEMO checklist. The assigned class will be that which had the highest correlation against the responses.
   c) AEMO will review the TNSP's allocation for unknown risks against the expectation for the assigned class (see Section 2.2.2).
   d) AEMO will work with the TNSP to resolve any missing cost components or differences in risk allocation treatments.
2. Review of cost estimates:
   a) The TNSP will provide cost estimate for each project option.
   b) AEMO will estimate the cost in parallel, using the Transmission Cost Database.
   c) AEMO will compare estimates and work with the TNSP to resolve or understand any significant differences in cost components or risk allowances. Importantly, as discussed in Section 2.2, the Transmission Cost Database will be used for developing estimates for conceptual Class 5 projects. When used for comparing against TNSP estimates, it is used to enable a further understanding of the breakdown of differing costs as given by the TNSP and for further benchmarking of the tool itself.
3. Final alignment of cost estimates:
   a) AEMO will carry out a final review of the TNSP's updated estimate.
   b) Where sufficient information is not provided to AEMO, or where missing or insufficient allowance is made for cost components or risk, AEMO will consider the requirement for an additional allowance based on the Transmission Cost Database.

2.3.4 Review outcomes

AEMO will receive project cost estimates from TNSPs for active projects before the release of the final *Electricity Network Options Report* and will provide a review of outcomes in this section of the final report.

2.4 Estimating operational expenditure for transmission

To estimate the operational expenditure (OPEX) for transmission projects, 1% of the total capital cost per annum is assumed as operation and maintenance cost for each transmission project. AEMO determined this approach following a review of TNSP revenue determinations[49].

2.5 Landholder payment schemes for transmission

AEMO recognises the important role of communities that host transmission lines and infrastructure, and the importance of land owners who host transmission being fairly compensated. Landholder payment schemes, which are additional to landholders' compensation, have been announced in various states, including the following:

- **New South Wales** – under the Strategic Benefit Payments Scheme[50] established in October 2022 for major new transmission projects, private landowners in New South Wales will be able to receive $200,000 per kilometre of transmission line hosted (in real 2022 dollars), paid out in annual instalments over 20 years. The Strategic Benefit Payments Scheme Policy Paper also highlights that "these benefit sharing payments will be made separately, and in addition to, the existing requirement to pay compensation to landowners for transmission easements under the *Land Acquisition (Just Terms Compensation) Act 1991*"[51].
- **Queensland** – Powerlink's SuperGrid Landholder Payment Framework[52] will apply for landholders and neighbours for easements for new transmission lines from May 2023. Landholders whose properties are traversed by an easement are entitled to payments under the *Acquisition of Land Act 1967* (ALA). To represent this framework, AEMO will apply a cost of $230,000 per km of new transmission based on advice from Powerlink, paid out in a lump sum – noting that landholders can decide between a lump sum or annualised payments.
- **Tasmania** – TasNetworks is consulting with landholders for proposed options for a Strategic Benefit Payment that will apply to landholders who host new major infrastructure for the North-West Transmission Developments. The Strategic Benefit Payment would be separate and in addition to compensation payable to landholders under the *Land Acquisition Act (1993)* (Tas)[53]. AEMO will apply these costs to the ISP when and if they are finalised and formally announced.

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[49] For more information, see page 55 of the 2023 IASR Consultation Summary Report at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-consultation-summary-report.pdf.

[50] EnergyCo. 'Strategic benefit payments scheme' web page. At https://www.energyco.nsw.gov.au/community/strategic-benefit-payments-scheme.

[51] New South Wales Government, 2022, *Strategic Benefit Payments Scheme policy paper*, October 2022, p. 5. At https://www.energyco.nsw.gov.au/sites/default/files/2022-10/policy-paper-strategic-benefit-payments-scheme.pdf.

[52] Powerlink's SuperGrid Landholder Payment Framework. At https://www.powerlink.com.au/sites/default/files/2023-05/SuperGrid-Landholder-Payment-Framework.pdf.

[53] *Land Acquisition Act 1993* (Tasmania). At https://www.legislation.tas.gov.au/view/html/inforce/current/act-1993-023.

- **Victoria** – in February 2023, the Victorian Government announced[54] that it will make payments to landholders for hosting new transmission projects, totalling $200,000 per kilometre of transmission line hosted and paid in annual instalments over 25 years. These new payments will apply to ISP and Victorian REZ transmission projects and are separate to any payments under existing arrangements for transmission easements under the *Land Acquisition and Compensation Act 1986*[55].

AEMO will consider announced landholder benefit payment schemes listed in this section in the ISP. In accordance with the AER's *Cost Benefit Analysis Guidelines* (CBA Guidelines), the cost of schemes that are funded by government will be treated as an externality that does not influence the cost benefit analysis, while the cost of schemes that are funded by consumers (for example, via regulated transmission charges) will be included in the cost benefit analysis as part of the cost of developing the relevant credible option. AEMO will jointly plan with the responsible TNSP or jurisdictional body to estimate a percentage of the total new transmission circuit line length which can prudently be assumed to be held by private landholders who will be eligible for these payments.

For the purposes of providing the ISP model with conceptual estimates to develop the ODP, each option will have a total new circuit length and an estimated percentage of the new circuit length that traverses through private land. This 'private land factor' will be determined through joint planning with TNSPs. For further detail on these new circuit lengths applied, please refer to the augmentation options in the IASR Workbook[56].

2.6 Economic, social and environmental costs and benefits for transmission

The high-voltage transmission infrastructure plays a crucial role in connecting all those who produce and consume electricity across the NEM – from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania. Within the context of the ISP, the high-voltage infrastructure, including towers, conductors, and substations, is critical to affordably meeting Australia's long-term energy reliability and decarbonisation goals.

The planning and delivery of transmission infrastructure relies on participation from a wide range of stakeholders. AEMO has an important role in producing the ISP – it presents a roadmap to help guide Australia's energy transition, and many large transmission infrastructure projects are first conceptualised in the ISP. However, there are also limitations in the granularity of information in the ISP. Transmission projects are inherently complex and must be refined, redesigned, rescheduled and potentially cancelled as more information becomes available.

AEMO acknowledges that high-voltage infrastructure plays a critical role in the energy transition, but also can have localised impacts to host landowners, communities and the broader environment. Planning the future of the grid is also a highly regulated process, and it is inter-related with and dependent on obtaining planning and environmental approvals under relevant state and federal legislation.

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[54] New payments for landholders who host new transmission. At https://www.energy.vic.gov.au/renewable-energy/transmission-and-grid-upgrades.

[55] *Land Acquisition and Compensation Act 1986* (Victoria). At https://www.legislation.vic.gov.au/in-force/acts/land-acquisition-and-compensation-act-1986/054.

[56] Consultation materials for the 2023 IASR are at https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

The regulatory framework

The ISP is carried out in compliance with the NER and AER guidelines. In accordance with these requirements, AEMO considers the cost of construction, maintenance, and operation of any network option, including compliance with laws, regulations, and administrative requirements. In relation to regulated network augmentations, only those matters which can be costed can be included[57] in the cost-benefit analysis that AEMO and TNSPs are required to undertake.

This includes aspects such as the cost of compliance with any planning and environmental legislation. For example:

- If a government requires a network project to secure a biodiversity offset to manage the impact of removing native vegetation, the cost of providing that offset will be incorporated into the project estimate.
- If a project requires new easements or substations, the cost of assembling the required land and easements will be incorporated into the project estimate.
- If the route of a project needs to avoid an area of environmental concern, the additional cost will be incorporated into the project estimate.
- If an overhead transmission option does not comply with planning requirements or environmental legislation, underground options may be considered.

Where an impact, or cost, is not included as a relevant consideration in the regulations, the regulations do not permit these matters to be considered[58]. Similarly, the regulations do not allow consideration of wider benefits of building or maintaining transmission infrastructure such as increased regional jobs, local manufacturing, utilisation of local contractors, training and apprenticeships, or economic opportunities unlocked or facilitated by the projects.

Importantly, while the regulatory process that underpins the ISP and any future RIT-T is undertaken on a cost benefit analysis, these are only some of the preliminary steps that occur before each project obtains the necessary planning and environmental approvals. Broader impacts are considered as part of the relevant jurisdictional environmental and planning assessment processes.

Overhead and underground options

The augmentation of the transmission network is essential to provide access to the existing transmission network for renewable generation in remote areas and to increase the capability to share electricity between regions. In some cases, augmentation within the existing transmission network is also necessary to supply major load centres.

Overhead lines are often an economic, flexible, and responsive design choice for augmenting the high voltage transmission network. These lines represent the vast majority of the Australian transmission network and have

[57] For further explanation of the cost estimation undertaken as part of the ISP process, see AER, Cost Benefit Analysis (CBA) Guidelines section 3.3.3 (Valuing Costs), at https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20guidelines%20-%202024%20-%20Version%203.pdf.

[58] The CBA Guidelines (page 20) require AEMO to exclude in any analysis under the ISP, any cost or benefit which cannot be measured as a cost to generators, DNSPs, TNSPs or consumers of electricity. At https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20guidelines%20-%202024%20-%20Version%203.pdf.

reliably served the community for many years. In certain circumstances, alternate design or technology choices may be feasible.

While AEMO makes conceptual design assumptions in the ISP, projects that become actionable will progress through the RIT-T. In this process, the TNSP must consider a range of feasible network options to meet the identified need, including credible alternate designs or technologies. These may include:

- alternate structure designs, including monopoles, guyed towers, and a variety of lattice towers
- alternate design methodologies, including insulated conductors or cables
- alternate construction methodologies, including helicopter or drone stringing and direct drilling
- alternate technologies, including high-voltage alternating current (HVAC) and high-voltage direct current (HVDC), and/or
- non-network solutions, including battery services that obviate the need to build new network.

Building overhead transmission lines may not always be the cheapest method to augment the network. Not every alternative will be credible or feasible given the objectives and economics of the individual project. Each TNSP will consider a wide range of options as the projects progress.

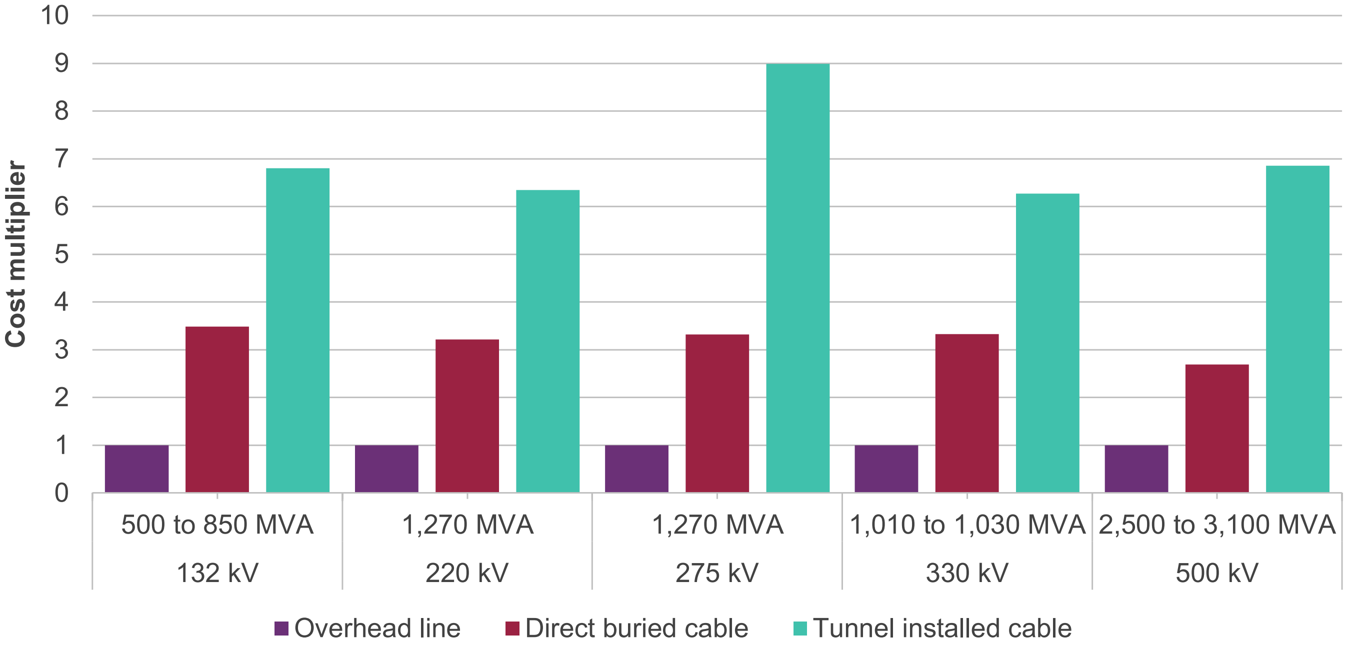
In the absence of detailed designs, AEMO has made the following assumptions for considering undergrounding in areas where overhead transmission lines are not expected to be technically feasible or are not compliant with planning requirements or environmental legislation:

- HVAC underground cable is technically feasible for shorter lengths of transmission (from 20 km for 500 kV to up to approximately 100 km for lower transmission voltages). Beyond these lengths, AC cables at high voltage level will be subject to very large charging currents, requiring significant reactive compensation and design considerations.
- For HVDC options, longer lengths of underground cable are likely to improve commercial feasibility relative to overhead options.
- Direct burial of cables is cheaper than tunnel installation, but is only suitable in non-urban areas. Built up areas will typically require tunnel-installed cable to avoid existing infrastructure. Maintenance is easier on tunnel-installed cables due to simpler access of the cable.

The Transmission Cost Database includes cost estimates for overhead transmission lines and underground cables, both of which vary significantly with voltage level and capacity.

Figure 9 shows a comparison of these cost estimates for given voltage levels and power transfer capacities. The HVAC option is included as a reference point. Data from consultants GHD indicates the costs of underground cables relative to overhead lines may have reduced from previously advised ‘four to 20 times’ to approximately ‘three to nine times’ higher than overhead lines. This is to be confirmed if underground AC transmission is a potential economic option. Direct buried cables are at the lower end of this range, while tunnel-installed cables are at the upper end.

Figure 9 Indicative unit cost multiplier from HVAC overhead lines to HVAC underground cables



Notes:

- AEMO will review the values shown in this chart and will seek additional data sources to confirm all values, particularly for tunnel installed cables, for the final 2025 *Electricity Network Options Report.* These values remain subject to review and confirmation against additional data sets.
- This chart shows cost factor increases relative to the respective overhead option on a generic unit cost basis. Underground 500 kV HVAC options cost more than 275 kV HVAC options, but the cost factor increase is higher when undergrounding a 275 kV HVAC option compared to undergrounding a 500 kV HVAC option.
- This chart has been prepared using AEMO's Transmission Cost Database and may not provide an appropriate comparison for all projects due to local circumstances.
- This cost comparison is indicative of the variable per unit cost of overhead lines and underground cables. The total project cost is sensitive to factors such as terrain, geotechnical constraints, and fixed cost factors associated with transition stations.
- Tunnel installed cable design is most applicable to underground cable projects in urban areas while direct buried cable can be suitable for projects in rural or remote areas. For greenfield transmission projects in rural or remote areas, it is appropriate to compare overhead with direct buried cable.

2.7 Market impacts on transmission costs

There is the potential that delivery of multiple coincident projects will impact transmission costs, both in labour and materials. AEMO has previously partnered with Infrastructure Australia for the 2021 *Market Capacity of Electricity Infrastructure* report[59] and the 2022 *Market Capacity of Electricity Infrastructure* report[60]. These reports studied the labour and material requirements to fulfil the NEM-wide generation and transmission projects included in the 2020 and 2022 ISPs. In addition, AEMO partnered with the University of Technology Sydney and RACE for 2030 to specifically examine the volume of labour required to deliver the infrastructure build set out in the 2022 ISP across the scenarios[61].

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[59] At https://www.infrastructureaustralia.gov.au/market-capacity-electricity-infrastructure.

[60] At https://www.infrastructureaustralia.gov.au/publications/2022-market-capacity-report#:~:text=Infrastructure%20Australia%20is%20pleased%20to,over%20the%20last%2012%20months.

[61] University of Technology Sydney. *The Australian Electricity Workforce for the 2022 Integrated System Plan: Projections to 2050. Revision 1*. At https://aemo.com.au/-/media/files/major-publications/isp/2022/supporting-materials/the-australian-electricity-workforce-for-the-2022-isp.pdf?la=en.

The Transmission Cost Database allows the selection of a known risk, referred to as market activity. The selection of this known risk is intended to reflect the impact on transmission costs of the concurrent delivery of large transmission projects that is attributable to competition for labour and materials. For example, setting this factor to "Tight" applies a 10% uplift to the costs of plant and materials, and labour. This factor will be applied to transmission cost estimates on a case-by-case basis and through extensive joint planning with TNSPs and jurisdictional bodies.

AEMO has amended the ISP Methodology to note that if generation or transmission build in the draft or final ISP is observed to be lumpy, sensitivity analysis could be conducted to assess the impact of limiting infrastructure delivery in the ISP based on supply chain outcomes.

2.8 Treatment of concessional finance for transmission projects

Concessional finance is a below-market interest rate loan offered by a government body. The AER's CBA Guidelines[62] were amended in November 2024 to include guidance on the treatment of concessional finance in the RIT-T and ISP following rule amendments by the AEMC[63] to allow the sharing of concessional finance benefits with consumers.

The CBA Guidelines recommend that AEMO follow the same approach to treating concessional finance in the ISP as RIT-T proponents must follow when applying the RIT-T. For RIT-T proponents, where the benefit from the below-market interest rate will be shared with consumers, the guidelines allow the present value of that benefit shared with consumers to be accounted for as a reduction in the cost to the RIT-T proponent.

The CBA Guidelines include information requirements for proposed concessional finance agreements at the RIT-T stage in order to justify an agreement's inclusion. The guidelines recognise that the inclusion of agreements still in negotiation at an early stage will need a greater level of supporting information to be provided to justify their inclusion compared to finalised agreements, noting that only concessional finance agreements that are reasonably likely to be executed should be included in the RIT-T assessment.

Given the ISP includes the consideration of projects prior to the RIT-T stage (or equivalent for jurisdictional investment frameworks) that are at a relatively early stage of development, it may be premature to consider concessional finance benefits for such projects in the ISP. AEMO proposes to rely on advice from the relevant government funding body and the AER on the appropriateness of including concessional finance for a specific ISP project, and the likelihood of an agreement being executed, for projects that have not yet commenced a RIT-T (or equivalent jurisdictional framework).

For projects that have commenced or completed a RIT-T (or equivalent), AEMO proposes to align the treatment of concessional finance in the ISP with that assessment. In addition to promoting ISP/RIT-T alignment which is important for processes like the AEMO feedback loop, satisfying information requirements for the inclusion of proposed concessional finance agreements for the purposes of a RIT-T assessment will provide AEMO with confidence that it is appropriate to include that same agreement or expected agreement in the ISP. While those

[62] At https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%2021%20November%202024.pdf.

[63] See AEMC, *National Electricity Amendment (Sharing concessional finance benefits with consumers) Rule 2024* at https://www.aemc.gov.au/rule-changes/sharing-concessional-finance-benefits-consumers.

information requirements do not apply to assessments progressed via jurisdictional frameworks, AEMO proposes that proponents satisfy the same requirements for consistency and to demonstrate that an expected concessional finance agreement is reasonably likely to be executed.

Where concessional finance is included in the ISP for a particular project, AEMO proposes to account for the agreement (or expected agreement) in the ISP cost benefit analysis in a manner consistent with the RIT-T assessment. Where concessional finance is included in the ISP but the agreement (or expected agreement) is not reflected in a RIT-T assessment, AEMO proposes to consult the relevant government funding body, AER and project proponent on the use of an appropriate accounting methodology. The CBA Guidelines include guidance on accounting for concessional finance in RIT-T assessments. AEMO proposes to align its accounting of concessional finance in the ISP with that guidance for simplicity and ISP/RIT-T alignment.

Consultation questions

3. Do you agree with AEMO's proposal for considering the inclusion of concessional finance for transmission projects in the ISP cost benefit analysis? Should AEMO align the treatment of concessional finance in the ISP with that in a RIT-T assessment? Should projects progressed via jurisdictional frameworks be treated in the same way?

2.9 Projected changes in transmission infrastructure costs over time

In addition to updating the Transmission Cost Database, AEMO has updated its treatment of costs for transmission projects delivered in future years[64].

In previous ISPs up to and including the 2022 ISP, it was assumed that the costs of transmission network augmentation projects would remain constant in real terms; that is, that costs would increase in line with economy-wide inflation. For the 2024 ISP, AEMO used cost forecasts that reflected changes beyond those attributable to economy-wide inflation[65], to recognise heightened project delivery costs being experienced by the transmission industry, and the anticipated impact on costs of a substantial increase in transmission network build, both domestically and internationally.

For the 2026 ISP, AEMO engaged GHD to undertake a refresh of the cost forecasting methodology[66]. This section notes the refreshed methodology to be used to prepare the forecasts for the transmission cost components, and the approach to be taken to apply them for transmission augmentation projects in the 2026 ISP modelling.

[64] An appropriately modified version of this approach will be applied to distribution network costs across the ISP horizon, for the distribution network opportunities presented in Section 5.1.2.

[65] Full details of the novel cost forecasting approach prepared and applied for transmission network options in the 2024 ISP are in the Mott Macdonald report, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[66] GHD. *2025 Forecasting tool and methodology report*, May 2025. At https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report.

2.9.1 Forecasts for transmission cost components

AEMO engaged GHD to refresh the forecasting methodology for projecting the cost of transmission projects. The methodology can be found in GHD's report summarising the cost forecasting methodology[67].

In the cost forecasting methodology, the components of transmission network projects are allocated into nine baskets. The price of goods or services in a particular basket is determined by a weighted mix of economic indices pertaining to that basket[68]. GHD has provided a set of escalation factors for each basket over the period to 2050 based on how the underlying indices are expected change. The nine baskets identified are:

- design, survey and project management
- construction works, commissioning and testing
- easement and property costs, and environmental offset costs
- overhead line
- underground cables
- switch bays, property site work and building
- transformers, reactors and synchronous condensers
- secondary systems, and
- switchgear, instrumentation, and converters.

AEMO will apply the GHD escalation factors to transmission augmentation project cost estimates in the ISP. AEMO expects that costs for transmission project resources will increase moderately in real terms, above the increases driven by recent global economic shocks. This cost trajectory reflects an expectation for demand for transmission project resources to grow, and that there may be a material lag before there is a supply-side reaction to elevated prices.

This escalation beyond economy-wide inflation is expected to apply in addition to the near-term market cost increases already observed in recent years, and as applied to the transmission network 'base costs' as outlined in Section 2.2.3. This approach aligns with the CSIRO's expectation, as outlined in GenCost 2024-25[69].

AEMO considers that this forecasting approach reflects reasonable consideration of a heightened level of demand for transmission project resources, noting that costs have already been elevated substantially by recent global price shocks and that these impacts are reflected in the updated Transmission Cost Database.

AEMO is planning to apply separate transmission cost forecasts to each scenario, although is still considering this decision. At AEMO's request, GHD has prepared a forecast for each scenario using assumptions that are consistent with the other inputs and assumptions that inform each scenario. Relative to the *Step Change* scenario, GHD assumed the following:

[67] GHD. *2025 Forecasting tool and methodology report*, May 2025. At https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report. .

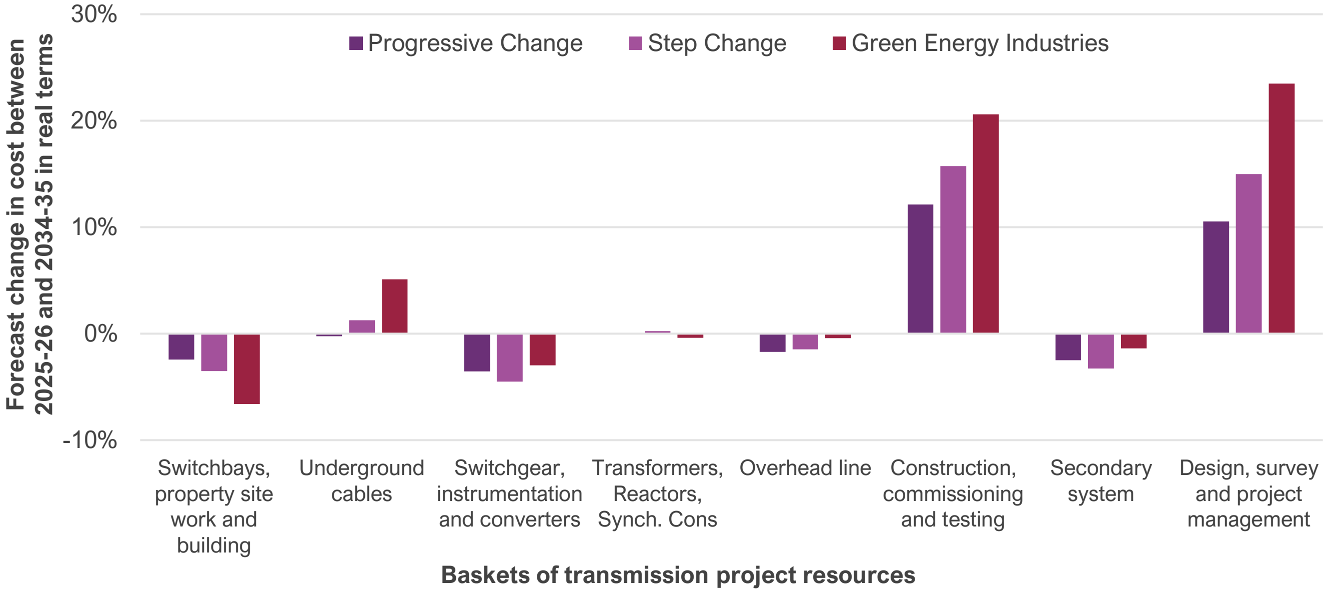
[68] Treatment for environmental offset cost components is summarised later in this section, and is not included in these baskets.

[69] See https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/GenCost.

- *Progressive Change* – lower domestic economic activity, lower volume of engineering construction work, higher crude oil price and lower base metal commodity prices.
- *Green Energy Industries* – higher domestic economic activity, higher volume of engineering construction work, lower crude oil price and higher base metal commodity prices.

Figure 10 and **Figure 11** present the forecast cost changes in real terms under each scenario from 2025-26 to 2034-35 and to 2049-50 respectively for each of the baskets of transmission project resources, except for easement and property costs. **Figure 12** presents the forecast cost change in real terms for easement and property costs from 2025-26 to 2049-50[70]. These figures show notable increases in the cost of labour for transmission projects and in easement and property costs, and more modest cost changes for plant and materials with increases for certain plant and materials and decreases for others. In addition, they show that differences between the forecasts for each scenario are relatively modest, with the exception of : construction works, commissioning and testing; and design, survey and project management.

Figure 10 Forecast change in transmission project resource costs (except easement and property costs) in real terms between 2025-26 and 2034-35



[70] AEMO will also apply the forecast cost changes for easement and property costs to environmental offset costs.

Figure 11 Forecast change in transmission project resource costs (except easement and property costs) in real terms between 2025-26 and 2049-50

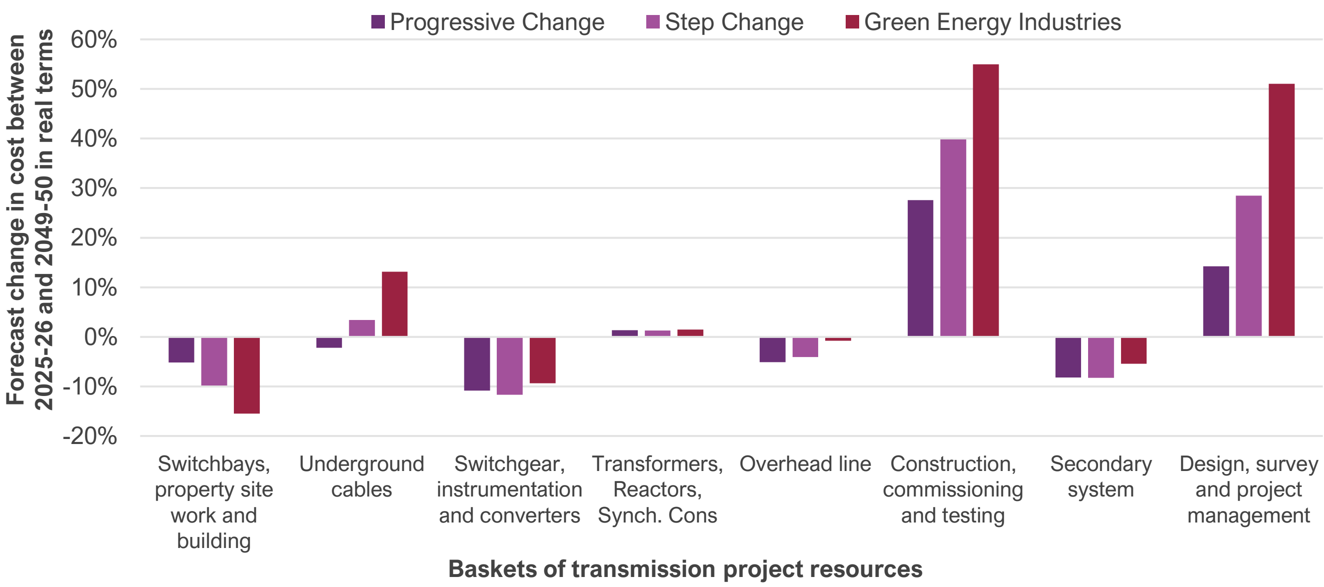


Figure 12 Forecast change in easement and property costs between 2025-26 and 2049-50

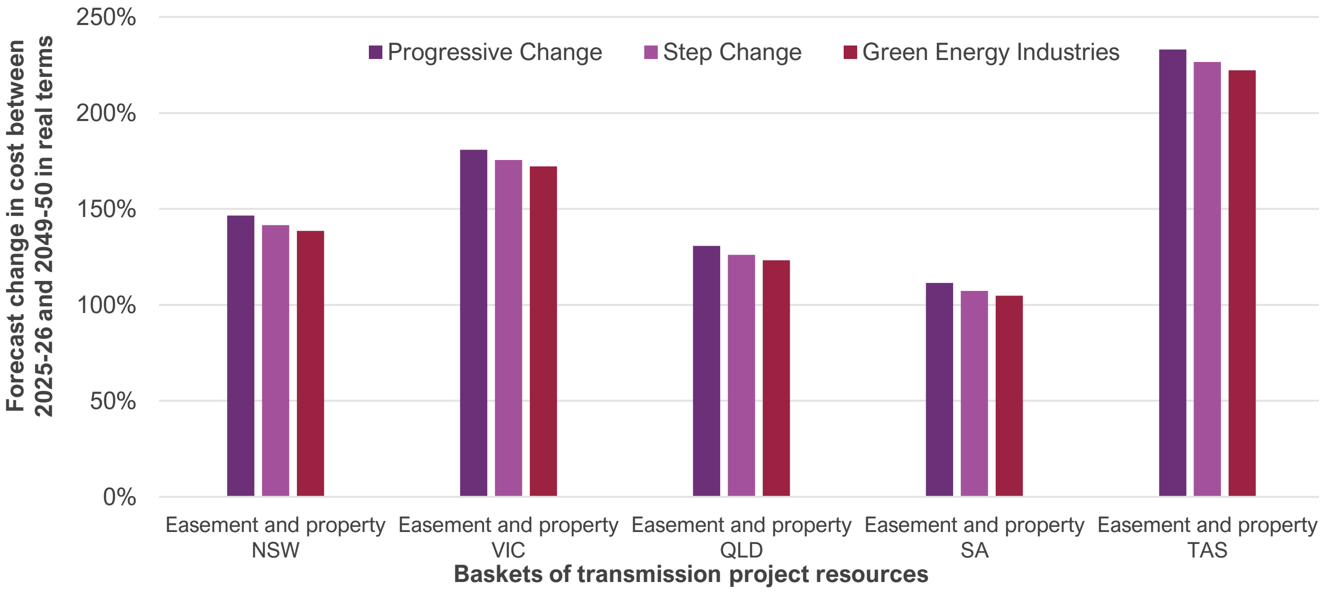
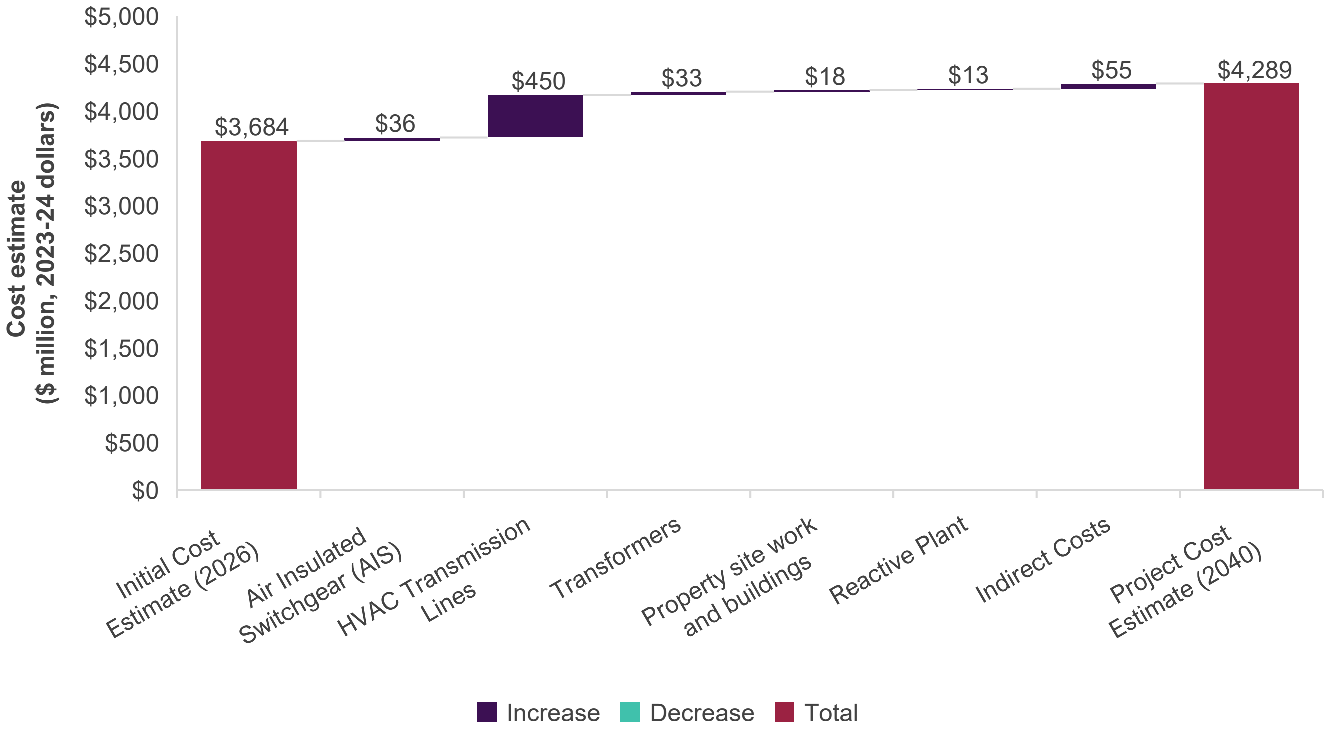


Figure 13 gives an example of the impact of applying escalation factors to a sample project (an augmentation option for the Central Queensland to Southern Queensland flow path). In this example, the largest change is projected for transmission line costs.

Figure 13 Application of transmission cost forecasting methodology to a sample project, in real terms



Note: The scope for the sample project includes 8 x 500 kV transformers and 330 km of 500 kV transmission lines.

AEMO has applied the proposed escalation factors to the transmission project options presented in this report, and presents the forecast average cost changes in real terms across the ISP horizon in **Figure 14**, for flow path options, REZ options and generator connection projects under *Step Change* scenario. As a result of these forecasts, the real cost difference of projects across the ISP horizon will change based on the composition of network elements that are included in the project. On average, a real cost increase of approximately 5% is projected between 2025-26 and 2029-30 for flow path, REZ and generator connection projects in the *Step Change* scenario.

Figure 14 Forecast average cost changes (real) for flow path, REZ and generator connection projects, *Step Change* scenario, 2025-26 to 2049-50

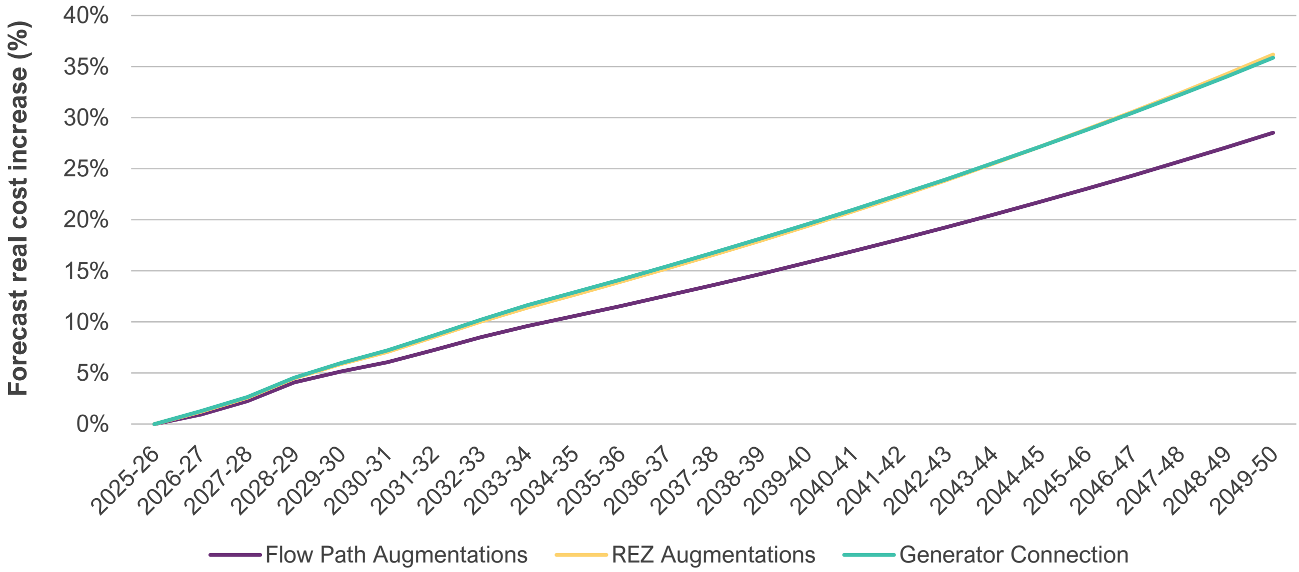
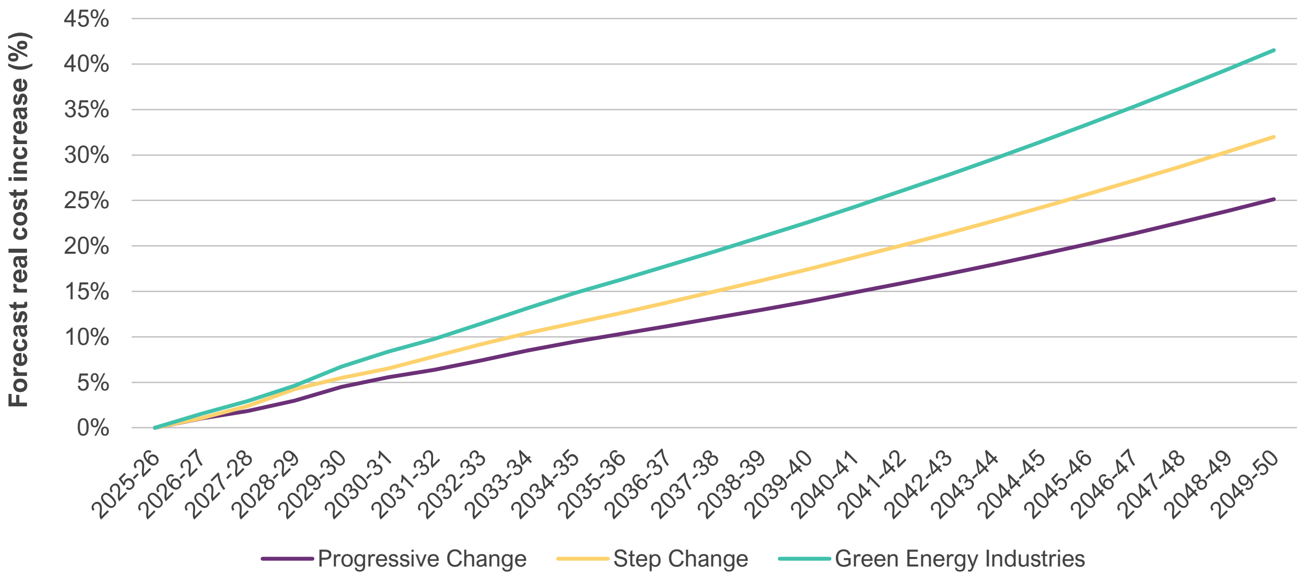


Figure 15 provides an indication of the different treatment for cost trajectories for transmission in the ISP. Costs are forecast to increase more under *Step Change* and *Green Energy Industries* scenarios, than under the *Progressive Change* scenario*.* Between 2025-26 and 2029-30, costs are forecast to increase by around 4% to 7% on average in real terms across the three scenarios.

Figure 15 Forecast average cost changes (real) for all project types, for all scenarios, 2025-26 to 2049-50



2.9.2 Application of transmission cost forecasting in the ISP

AEMO will apply transmission cost forecasts to transmission augmentation projects which are actionable ISP projects, future ISP projects, and other augmentation options:

- For cost estimates produced by TNSPs and jurisdictional bodies – AEMO will only apply the transmission cost forecasts beyond the earliest in-service date (EISD) for the project. This is because TNSPs and jurisdictional bodies typically estimate the cost of a project for delivery at the EISD. An exception may apply if AEMO does not consider that the project proponent has provided an estimate for delivery date at the EISD.

- For cost estimates produced by AEMO in its National Transmission Planner function – AEMO will apply transmission cost forecasts. This because cost estimates produced using AEMO's Transmission Cost Database reflect project delivery costs as of 2023-24 and are in 2023-24 dollars. For the Draft 2026 ISP and final 2026 ISP, AEMO may make a separate adjustment so that all costs are presented in 2024-25 dollars.

Consultation questions

4. What feedback do stakeholders have about AEMO's proposed forecasting approach for transmission costs over the ISP horizon?
5. What feedback do stakeholders have about AEMO's proposal to apply different forecasts for transmission project costs across each scenario?

2.10 Transmission project lead time

The ISP ODP is strongly influenced by the lead times and EISDs assumed for transmission projects. These projects may already be committed or anticipated projects[71] from TNSPs and other organisations, or they may be more speculative options which are less certain or progressed.

The ISP Methodology includes the ability for AEMO to revise EISDs provided by TNSPs and other organisations if needed, for example to better incorporate the uncertainty associated with transmission project lead time[72]. AEMO has a strong preference to only adjust EISDs through close joint planning and collaboration with the relevant TNSPs and/or jurisdictional bodies. However, AEMO considers it prudent to reserve the ability to apply adjustments to lead times based on transparent stakeholder feedback, and where there is sufficient evidence to support the adjustment[73].

AEMO has collaborated with TNSPs and jurisdictional bodies to understand project lead times for the augmentation options presented in the Draft 2025 *Electricity Network Options Report*. AEMO has not adjusted any project lead times beyond what has been advised by TNSPs and jurisdictional bodies.

[71] Committed transmission augmentation projects meet five criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment, and necessary financing arrangements. Anticipated projects are in the process of meeting at least three of the criteria. Details about the criteria are provided in AEMO's Transmission Augmentation Information publication, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[72] The current ISP Methodology is at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology. AEMO is currently completing a consultation on a review of the ISP Methodology, with information at https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[73] The update to the ISP Methodology also included an amendment to apply an actionable window concept. This change reflects the need to repeat regulatory approvals and other work if the actionable project status is removed and subsequently restored. This only impacts projects that were actionable in the previous ISP, and is mentioned here for completeness but will not affect project lead times noted in the 2023 *Transmission Expansion Options Report*. Further information about these updates is outlined the ISP Methodology consultation materials, particularly AEMO's *Consultation summary report - Update to the ISP Methodology,* at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/consultation-summary-report---update-to-the-isp-methodology.pdf?la=en.

Project lead time categories are defined as follows:

- a short lead time is within 3-5 years
- a medium lead time is within 6-7 years, and
- a long lead time is beyond seven years.

2.11 Social licence for transmission projects

AEMO recognises the importance of social licence related to the energy transition, and acknowledges that this is an area of continued learning and development for the organisation and the energy sector.

The Federal Government's February 2024 review of the ISP directed AEMO to "incorporate, to the degree that AEMO can, community concerns or sensitive locations into its planning or in the selection of the Optimal Development Path (ODP)".

Although social licence may have several definitions[74], in this report AEMO has considered, where possible, social licence in the context of "community sentiment" or acceptance of energy infrastructure.

AEMO has deepened its social licence considerations in the 2025 *Electricity Network Options Report* through:

a) **conceptual design and location**, including refreshing land use data to consider more land use categories and applying the updated data when preparing cost estimates using AEMO's Transmission Cost Database, and working with joint planning bodies to incorporate any early sentiment considerations in transmission options where possible, and

b) **cost estimates,** by updating AEMO's Transmission Cost Database which is used to inform conceptual option cost estimates, including reflecting network information about updated cost estimates related to deeper and earlier community engagement, and by using the refreshed land use data to prepare individual project cost estimates.

2.11.1 Social licence consideration throughout the transmission planning process

AEMO, as the national system planner, does not have responsibility for delivery of transmission projects[75]. Much of the responsibility to understand and engage with local communities sits with relevant transmission project developers and tiers of government. As such, unless informed by specific feedback from transmission project developers, AEMO's consideration of social licence is at a high level and limited to the very early stages of the transmission lifecycle.

[74] In the 2024 ISP Appendix A8 Social Licence (https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a8-social-licence.pdf?la=en), AEMO sought to define social licence at three key levels: social acceptance of the broader transition; social acceptance and mobilisation related to CER, including the ability for CER such as electric vehicles and batteries to be coordinated; and local community acceptance of new infrastructure development. For the purposes of the *Electricity Network Options Report*, AEMO will consider the final aspect.

[75] The exception to this statement is that AEMO Victorian Planning (AVP) has a transmission planning function in Victoria.

AEMO has engaged extensively with environmental and governance experts, planning officials, network project developers and members of its ISP Consumer Panel and Consumer and Community Reference Group, on its approach to incorporating social licence in its planning.

Figure 16 below shows how social licence is considered through stages of transmission development, broadly aligned with the stages in the Federal Government's *National Guidelines for Community engagement and benefits for electricity transmission projects*. For simplicity, the project stages in the diagram below are shown in a linear fashion, but it should be noted that the timing of activities may not be linear.

Figure 16 Social licence in electricity transmission network planning

AEMO as national transmission planner

As part of the Integrated System Plan (ISP), AEMO identifies conceptual options via joint planning with network service providers and jurisdictional bodies, identifies network needs and conducts market modelling and an economic feasibility assessment.

Project-specific assessment by Transmission Network Service Providers (TNSPs) and jurisdictional bodies

AEMO's ISP triggers the Regulatory Investment Test for Transmission (RIT-T) by TNSPs for actionable ISP projects which assess an individual project at a more granular level than the ISP. Actionable projects that do not undergo the RIT-T are progressed under a jurisdictional framework.

Project delivery, operations, maintenance and decommissioning by TNSPs

TNSPs undertake the delivery of the project, from pre-construction approvals, to construction, to operation and maintenance, to decommissioning and renewal. They are responsible for obtaining, building and maintaining of local community acceptance for the project.

Project concept and option consideration and selection	Need identification	Economic feasibility assessment	Project-specific assessment	Cost recovery and regulatory approvals	Delivery of preferred option, route refinement	Pre-construction approvals	Construction	Operation and maintenance	Decommission or renewal

High-level consideration of social licence → **Early engagement by networks with communities** → **Detailed and localised engagement with communities and landholders**

Social licence is considered at a high level in the ISP, including through the identification and refinement of conceptual options, and preparatory activities for actionable and future ISP projects. AEMO does not undertake project-specific or localised engagement as this sits with TNSPs, project developers, and jurisdictional bodies, but does take into account data on localised community sentiment at this early stage if advised.

Examples of high-level considerations:
- Land use mapping
- Location selection of renewable energy zones

RIT-T proponents must consider social licence issues when identifying options, publish and report against a stakeholder engagement plan and meet community engagement expectations defined in the National Electricity Rules. The AER considers the prudent and efficient costs of network projects, including social licence costs. Non RIT-T assessments or projects assessed under jurisdictional frameworks must also consider detailed cost-benefit analyses and social licence.

Examples of social licence considerations:
- Re-routing of lines due to community concerns

TNSPs are responsible for obtaining, building and maintaining social licence during the construction, maintenance and decommissioning of transmission lines.

Examples of social licence considerations:
- Community benefit sharing arrangements
- Easement and payment arrangements with landholders

Note: AEMO's consideration of social licence is limited to the very early stages of the transmission lifecycle (marked in purple).

2.11.2 Conceptual design and location

In this report, AEMO provides conceptual options for a range of transmission augmentation projects. AEMO collaborates with TNSPs and jurisdictional bodies to co-design conceptual network options for the ISP. Where potential routes and locations are shown for projects, these are highly indicative only and should not be considered as fixed locations or routes.

AEMO has sought to incorporate social licence considerations in successive IASRs and ISPs through extensive consultation with governments, TNSPs, consumer and community advocates and other stakeholders.

TNSPs and jurisdictional bodies also incorporate social licence considerations in their project design and cost estimates for projects which are under development. AEMO joint plans with these bodies to incorporate known social licence considerations into the options included in the *Electricity Network Options Report.*

AEMO expects that consideration of social licence matters for the NEM will continue through expansion of the already strong collaboration between generation developers, TNSPs, and NEM jurisdictional bodies and community representatives. This includes ensuring the design of transmission assets take advantage of available design and technology choices to minimise their impact on land use.

AEMO, TNSPs and jurisdictional bodies met for a series of workshops between November 2024 and February 2025 to engage on how to further consider social licence in the transmission options prepared for the ISP. As well as discussing existing network designs, new generation areas, and economic and technical requirements, these workshops explored how community sentiment is currently and could be further considered in conceptual project options. Participants shared examples of community sentiment around energy infrastructure, best practices on community engagement, key lessons from projects, and potential applications for publicly available sentiment data to report modelling. Conversations also explored opportunities to update land use data inputs with more detail on social and environmental factors (see Section 2.11.3).

AEMO and the joint planning bodies identified the following examples of how land use planning and community considerations are able to actively shape transmission projects to support consideration of social licence:

- transmission line re-routing, including extending and changing the type of transmission lines to avoid urban centres and localities, private and public land, cultural heritage, Native Title, water crossings, environmental/biodiversity protected or soon to be protected areas, and avoiding endangered species habitats, across all NEM regions,
- rerouting and extending lines to avoid other infrastructure development (for example, airports in New South Wales), and other release areas for development (such as hydrogen projects in South Australia),
- considerations in Victoria for emerging peri-urban residential areas, and landscapes with multiple values (wetlands and mountains with cultural heritage, agricultural and environmental considerations),
- increased collaboration with communities to co-design routes and benefit sharing programs,
- increased two-way collaboration with local and state governments to improve information flows on land use or impending land use determinations, and
- increased consideration of alternatives including non-network options and undergrounding options.

Following the ISP, some projects will continue to be developed, while others will remain conceptual.

In the latter stages of the project development lifecycle, changes usually occur through community engagement and conversations with project developers (refer to Figure 16 above). As such concerns are localised and granular, the responsibility to meaningfully consider such community concerns sits with project developers, rather than AEMO during the development of the ISP.

AEMO also does not consider it prudent to pre-empt such conversations during the early planning stages of the ISP, and recognises that communities and individuals impacted must be able to provide specific and measurable feedback through detailed consultation processes with relevant project developers, which should ultimately guide the development path and progress of individual projects.

Overall consideration of social licence matters in the 2026 ISP will be through:

- selection of forecasting and planning scenarios, including trends relevant for social licence such as economic conditions in Australia and the pace of investment to decarbonise the economy,
- use of land use limits and resource limits in the ISP modelling, as consulted on through the IASR process,
- estimation of conceptual easement lengths that avoid the most complex land areas, using publicly available land use datasets (see Section 2.11.3),
- selection of transmission augmentation options through collaboration and joint planning with TNSPs, jurisdictional bodies and other stakeholders,
- inclusion of transmission project lead times in the modelling to incorporate time for community engagement,
- selection of locations for potential REZs through consultation on successive IASRs and ISPs,
- consideration of the input and feedback from external stakeholders, including AEMO's Consumer and Community Reference Group (CCRG) and the ISP Consumer Panel, and
- potential application of any other appropriate methods to help inform selection of the ODP.

2.11.3 Application of updated land use data

To ensure the latest information is considered, AEMO engaged consultancy firm Jacobs to refresh its land use data inputs from 2019, as well as seeking to introduce additional localised and available social, environmental, First Nations and agricultural considerations where possible. The land use criteria scores[76] were also reviewed, with more data points to show more complexity in mapping. Inputs were sourced from publicly available data, with the intention of identifying how communities and local governments have stated or indicated they wish to use their land to date. Notably, the data does not consider future opportunities, plans, and aspirations, such as regional development plans, or localised, informal arrangements between groups, as these may be subject to higher levels of uncertainty. These plans and arrangements are nonetheless still important at the post-conceptual stages of the transmission lifecycle and should be gathered by project developers from localised community engagement.

The key updates made to the land use data provided by Jacobs were to:

- revise the assessment of First Nations heritage, providing greater differentiation regarding possible project outcomes,

[76] Jacobs developed an updated assessment framework of land use types, overlaying criteria for environmental, cultural heritage, land use and approvals, geotechnical, community, climate and other factors, to obtain "scores" for complexity of land use.

- differentiate agricultural land types that are less compatible with hosting transmission infrastructure,
- expand the geotechnical considerations for transmission infrastructure, and
- take a new approach to identifying population centres and residential areas, including the distribution of the population based on Australian Bureau of Statistics Census data.

Further details are provided in Jacobs' report, published alongside the Draft 2025 *Electricity Network Options Report*[77]. A complexity score is assigned to land parcels within the NEM, as illustrated in **Figure 17**, with a resolution of at least 547 metres x 631 metres, evaluated by adding individual scoring criterion for environmental, cultural heritage, land use and approvals, geotechnical, community, climate and other factors, to obtain overall "scores" for complexity of land use. AEMO has published these datasets[78] and Jacobs' report alongside this Draft 2025 *Electricity Network Options Report*.

In this report, AEMO has used this complexity data provided by Jacobs to develop desktop estimates of easement lengths for conceptual transmission options, and has applied those updated lengths to prepare cost estimates. For transmission options that are more progressed, AEMO has used more accurate estimates provided by TNSPs. For the conceptual options, AEMO starts with a direct straight-line route between two substations described in the scope of the transmission option, and subsequently re-routes the path of each transmission option to connect the substations, avoiding the most sensitive areas such as national park and environmentally sensitive areas using the land use complexity data results. The 'least complex path' between the two substations to connect the transmission line is chosen, and the total path length is used to estimate the easement length reported for conceptual options. The least complex path may be up to 20% longer than the straight-line estimate, which could traverse highly complex areas.

It is important to note that AEMO's consideration of land use data is not considered a proxy for social licence or community acceptance – this must be actively sought by the project developers from communities.

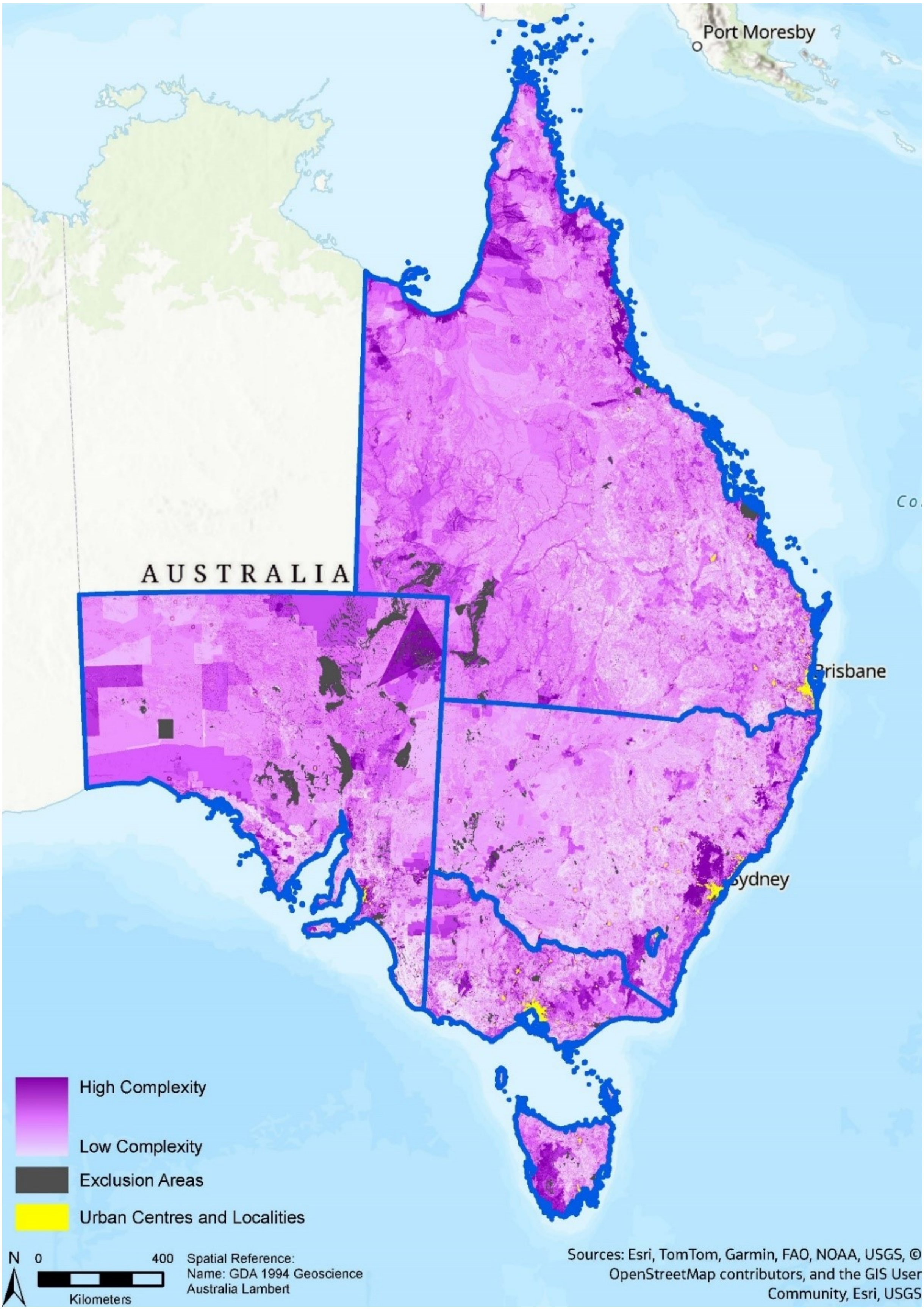
AEMO engaged closely with TNSPs and jurisdictional bodies when preparing this material and approach. This land use complexity assessment has been applied at the conceptual stage of potential transmission projects, and is not a substitute for the close engagement and consideration that would take place to potentially develop any particular transmission projects through delivery.

Figure 17 demonstrates the outcomes of the updated land use data in the NEM. The darker purple areas represent higher complexity areas, while lighter purple or white represents lower complexity areas, and grey represents exclusion zones.

[77] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/jacobs-strategic-land-use-transmission-assessment-report.

[78] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/jacobs-strategic-land-use-transmission-assessment-GIS-data.

Figure 17 NEM-wide land use complexity data



2.11.4 Updating community and stakeholder engagement activity costs in the Transmission Cost Database

AEMO engaged consultancy firm GHD to update the Transmission Cost Database which is used by AEMO to prepare cost estimates for conceptual future ISP projects (see Section 2.2.3). This included updating costs for completing community and stakeholder engagement activities for transmission network projects, with reference to the latest information available from TNSPs and jurisdictional bodies in the NEM. Further information is available in the GHD report published as a reference material alongside the Draft 2025 *Electricity Network Options Report.*

2.11.5 Community sentiment research

In addition to land use and cost factors, AEMO notes that there is a range of publicly available research on community sentiment and attitudes towards new energy infrastructure, which can be used to inform approaches on building and maintaining social licence in transmission planning.

The reports, summarised in **Table 10** below, show that social licence and community sentiment towards transmission development is varied, challenging, and complex. While most data studies were targeted at a nationwide or regionally representative level, the datasets are ultimately not appropriate for AEMO's modelling purposes, due to survey confidentiality, geolocational data availability, and sampling sizes. AEMO is also mindful that, as sentiment is dynamic in nature, survey results offer only a 'point in time' view and sampling may not include all relevant groups' opinions. Moreover, sentiment might change drastically as discussion shifts from the energy transition in general terms to hosting of transmission in people's communities.

Insights show that a significant number of Australians (between 47% and 66% across various reports) support the concept of the energy transition or feel positive towards it, but highlight that there is little or limited knowledge about large renewable infrastructure, technology, and about the energy transition in general. This suggests the need for enhanced educational efforts and communication strategies to ensure the public fully comprehends the importance and implications of the energy transition.

Most areas report moderate attitudes towards living near energy infrastructure and transmission lines, but peri-urban and rural areas naturally have stronger sentiments about such developments. Trust remains fragile and significant gaps in knowledge remain, with public confidence in government, industry and transmission developers remaining low, particularly in impacted communities.

While stakeholders have proposed that AEMO consider multi-criteria assessment frameworks to determine the level of community acceptance for specific transmission projects, AEMO concludes that it is neither appropriate for its role in conceptual transmission planning (see Figure 16 above), nor feasible for AEMO to gather and tangibly apply such data to the modelling at this stage. There are already multiple parties engaging communities in these project areas and, as shown in Figure 16, TNSPs, jurisdictional planning bodies, and project developers are better placed for obtaining and maintaining social licence, including listening to localised community concerns.

AEMO encourages transmission planners and project developers to continue to engage communities early and meaningfully, understand local impacts and concerns, and support them to make informed decisions. Planners and developers should do so in accordance with national guidelines such as the National Guidelines for

Community Engagement and Benefits for Electricity Transmission Projects[79] and industry practices such as the Energy Charter's Social Licence Better Practice Guideline[80], and implement recommendations from the Australian Energy Infrastructure Commission's Community Engagement Review[81], released in February 2024.

Table 10 Summary of key findings from publicly available research on community sentiment towards new energy infrastructure

Report	Key findings relating to sentiment on energy or energy infrastructure
CSIRO Australian attitudes to the energy transition research • **Released April 2024** • **Over 6,700 participants** **https://www.csiro.au/en/research/environmental-impacts/decarbonisation/energy-transition**	• More than 80% of Australians would tolerate living within 10 kilometres of solar or wind farms. • However, this falls to 77% for transmission lines, with main concerns being reduced visual attractiveness of local landscapes and devalued property.
SEC Newgate, Mood of the Nation • **Released quarterly, most recent update April 2025** • **Tracking of 36 national priorities** • **At least 1,000 participants per survey** **https://www.secnewgate.com.au/mood-of-the-nation-february-2025-summary/**	• Between June 2023 and April 2025, acting decisively on climate change and transitioning to renewables have generally remained between priority #21 to #29 out of 36 priorities. • From June 2022 to April 2025, positivity towards the renewable transition has ranged between a peak of 70% (in August 2022) and a low of 47% (in September 2024).
KPMG, The Human Side of the Energy Transition • **Released 2024 and 2025, with datasets collected in 2022, 2023, and 2025** • **The 2025 study had 1,012 participants, with an additional 303 surveyed who live in areas of energy infrastructure** **https://assets.kpmg.com/content/dam/kpmg/au/pdf/2025/human-side-of-energy-transition-2025.pdf**	• From November 2022 and January 2025, between 63% to 66% of Australians support the concept of the energy transition once informed. However, public understanding of the energy transition remains low. Between November 2022 and January 2025 only 17-27% of people reported at least some understanding.
RE-Alliance and Essential Media, Talking renewables to the regions • **Released July 2024** • **2,000 regional respondents in New South Wales, Victoira and Queensland** • **Stakeholder interviews and online focus groups** **https://essentialmedia.com.au/wp-content/uploads/2024/07/Talking-Renewables-to-the-Regions_170724.pdf**	• While a clear majority (56%) support the general idea of a transition to renewable energy, no-one feels well-informed about what the plan at either a regional or national level is. • The unifying theme was that the developments were being done to communities not with them. There was a lack of agency and buy-in to the transition. Consultation is transactional and bureaucratic, and there is deep distrust of energy companies and the government.
Australian Energy Infrastructure Commission, Community Engagement Review • **Released February 2024** **https://www.aeic.gov.au/news-media/news/community-engagement-review-report**	• Main recommendations included reducing unnecessary engagement through better site selection, assessment and planning processes, selecting only reputable developers and motivating them to achieve best practice, and the need to improve community understanding and acceptance of the transition through clear information, appropriate governance, and sustainable benefit sharing.
Australian Energy Infrastructure Commission (AEIC), Annual Report 2023 • **Released July 2024**	• In 2023, the AEIC Office received a growing number of transmission cases, with 57 complaints

[79] At https://www.energy.gov.au/sites/default/files/2024-07/national-guidelines-community-engagement-benefits-electricity-transmission-projects.pdf.

[80] At https://www.theenergycharter.com.au/wp-content/uploads/2023/05/The-Energy-Charter_Better-Practice-Social-Licence_2023_GUIDELINE.pdf.

[81] At https://www.aeic.gov.au/news-media/news/community-engagement-review-report.

Report	Key findings relating to sentiment on energy or energy infrastructure
https://www.aeic.gov.au/resources	about nine proposed large-scale transmission projects out of 149 new cases. • Complaints about transmission lines are generally complex, with several systemic issues identified such as transmission line route selection, land access arrangements, and communication about agricultural activities allowed under proposed transmission lines.

Consultation questions

6. Do you have any feedback on AEMO's land use mapping approach, or other aspects AEMO could consider for future improvements?

2.12 Distribution network opportunities

This section provides the methodology and process for collecting distribution network data and how this data will be incorporated into ISP inputs.

2.12.1 Background

On 19 December 2024, the AEMC published its Final Determination for AEMO to provide a clearer articulation of the expected development of CER[82] and other distributed resources[83] within the ISP as a result of the Federal Government Review of the ISP.

AEMO has engaged collaboratively with DNSPs to develop the most pragmatic approach for incorporating distribution network data on CER and other distributed resources opportunities as inputs into the 2026 ISP[84]. This will allow the ISP to assess the capability of distribution networks to accommodate the forecast CER penetration in the NEM and identify macro-level investment in distribution networks to efficiently support aggregate CER operation and the uptake of other distributed resources. This data-driven approach will help enable AEMO to optimise the development of the power system through the ISP, recognising the important role that distribution networks have in supporting the ongoing growth in consumer-generated power and flexible demand.

[82] In AEMO's forecasting approach, CER refers to embedded solar systems and battery devices that are owned by consumers. In general, these are residential and commercial rooftop PV systems less than 100 kilowatts (kW), and battery systems less than 5 megawatts (MW), and electric vehicles (EVs). The CER definition currently excludes larger PV and Other non-scheduled generation, and utility-scale sub-transmission generation dispatched by the NEM Dispatch Engine (NEMDE). For AEMO's current CER forecasts, see the current IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[83] In AEMO's market modelling approach, 'other distributed resources' are considered as resources which are not at the utility-scale but are larger than those referred to in the CER definition in footnote 1.

[84] AEMO will release a consultation paper in June 2025 to begin consultation on the *Demand Side Factors Information Guidelines*, which are required to be developed and published by 19 December 2025. AEMO has worked collaboratively with DNSPs to gather initial data in this report, for application in the Draft 2026 ISP, ahead of the information guidelines being released.

2.12.2 Approach to identifying distribution network opportunities

Historically, the ISP has assumed that distribution networks would be augmented to facilitate the level of forecast CER and other distributed resources in a given scenario and has not included the costs associated with these augmentations. For the 2026 ISP, AEMO is assessing for the first time the scale of distribution network augmentation to facilitate the higher levels of aggregate CER operation assumed in the ISP and estimating at a high level the costs associated with that. AEMO will assess the capability of distribution networks to accommodate aggregate CER operation, and identify the scale of macro-level investments in distribution to efficiently support aggregate CER operation and the uptake of other distributed resources. These will be inputs into the market model used to assess the ISP[85], alongside utility-scale generation, storage and transmission to supply electricity consumers in the NEM[86].

Most of the CER and other distributed resources across the NEM are connected to low voltage networks. The constraints and associated opportunities to enable higher aggregate CER operation are also primarily at the low voltage level, meaning the opportunity assessment needs to be calculated at this level. While the 2024 ISP had a focus on five NEM regions with circa 300 bulk supply points, the 2026 ISP will consider low voltage networks for the first time.

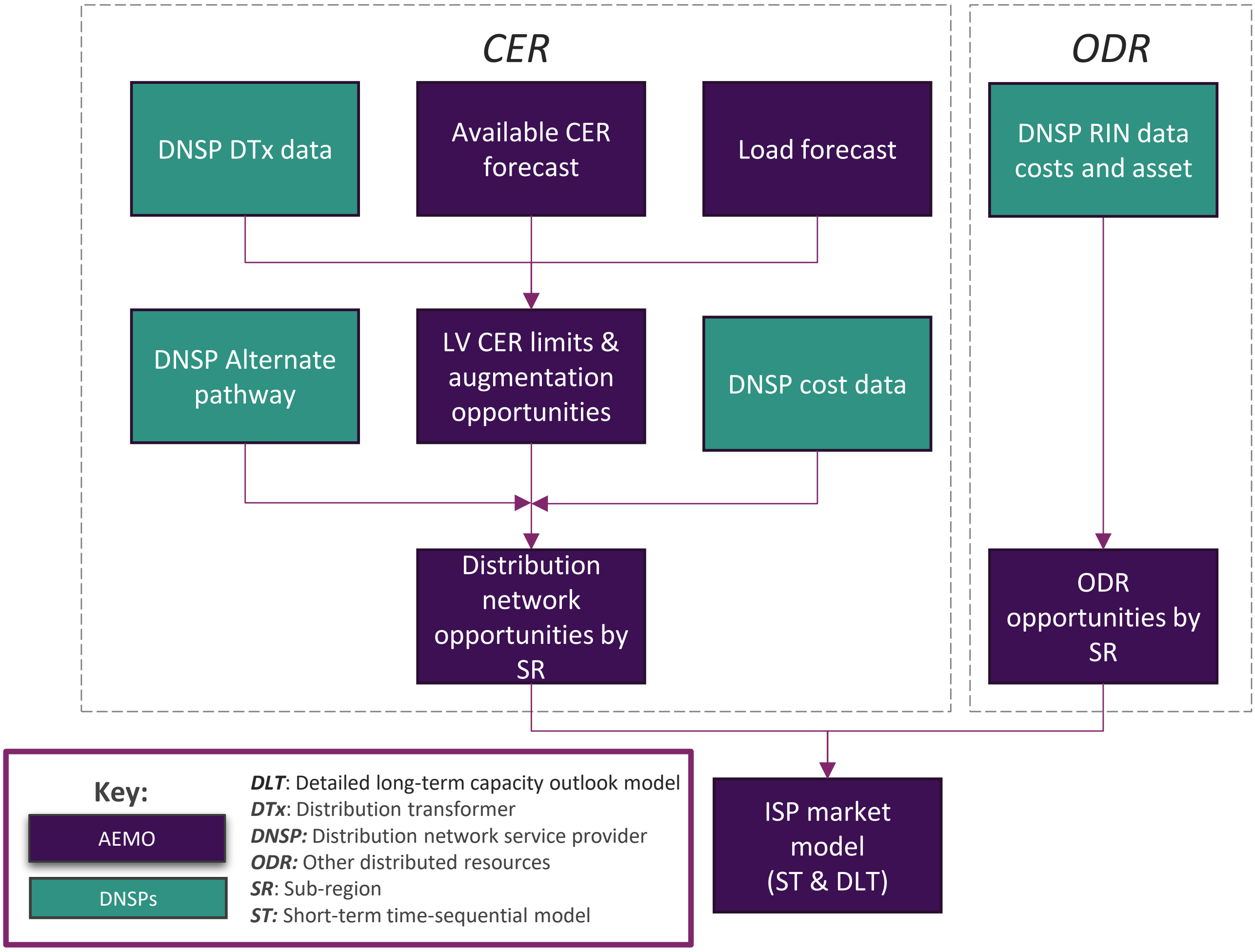
The number of relevant data points makes this task very challenging. Across the NEM, this requires consideration of over 500,000 low voltage transformer sites and the CER connected to over 9 million customers. Given this, AEMO acknowledges that the approach adopted for the 2026 ISP will necessarily be a high-level representation of the complex distribution networks within the NEM. AEMO recognises that there are alternative methodologies for incorporating distributed demand-side factors and that this initial approach adopted for the 2026 ISP is part of an iterative evolution as the data quality and modelling approaches improve over successive ISPs.

Figure 18 shows the approach that has been undertaken to identify the size and cost of the CER and other distributed resources opportunities in distribution networks. The following sections outline each of these stages.

[85] Further information about the capacity outlook model and time-sequential model used to undertake the ISP market modelling is in the ISP Methodology. AEMO is currently completing a review of the ISP Methodology, with more information at https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology.

[86] AEMO acknowledges that the 2026 ISP model is unable to represent lower voltage constraints in detail, meaning CER curtailment and associated alleviation costs have to be aggregated before feeding into the ISP model.

Figure 18 Approach to including distribution network opportunities in the ISP model



2.12.3 Consumer energy resources forecast

For the 2026 ISP, the approach to incorporate distribution network opportunities means AEMO needs to forecast CER capacity (future uptake) and forecast CER availability (traces), at the same low voltage level that DNSPs have provided data for their assets outlined in Section 2.12.5.

AEMO proposes to take the forecast CER capacity by postcode, as outlined in AEMO's Electricity Demand Forecasting Methodology[87], and map this installed capacity to each distribution transformer asset through the following process:

1. The postcode-level forecast CER capacity is first disaggregated to the customer connection level (to each dwelling[88] proportionally) within the postcode. AEMO then maps the closest distribution transformer (DTx) to each address and aggregates the values. This maps forecast CER capacity by postcode to distribution transformer.

[87] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf?la=en.

[88] See https://data.gov.au/data/dataset/geocoded-national-address-file-g-naf.

2. AEMO then applies adjustments to the DTx-level forecast CER capacity derived from the previous step to be consistent with the aggregated forecast CER capacity at each transmission node identifier (TNI).

This process is designed to be consistent with AEMO's forecast at the TNI level, while capturing the spatial diversity of the postcode level CER capacity forecasts.

2.12.4 Low voltage level load forecast

For the 2026 ISP, the approach to distribution network opportunities means AEMO also requires load forecasts at the same low voltage DTx as CER forecasts and DNSP assets.

AEMO's proposed process for disaggregating the TNI-level underlying demand traces (half-hourly, for all weather years, scenarios, and forecast years) to produce underlying demand for each DTx involves:

1. Disaggregating forecast underlying demand traces from each TNI to its downstream Zone Substations (ZSS).
   - AEMO disaggregates the TNI-level underlying demand traces to the ZSS, using a combination of historical demand traces, historical solar PV installation data, irradiance information for each ZSS. Statistical methods are applied to address data quality gaps. AEMO computes ZSS contribution factors, which represent the ZSS' contribution to TNI demand at each half-hour interval, and when applied to TNI-level underlying demand traces provide ZSS-level underlying demand traces.
2. Disaggregating forecast traces from each ZSS to downstream distribution transformer.
   - AEMO further disaggregates the ZSS-level underlying demand traces to the distribution transformer by using historical maximum and minimum demand (operational) and installed PV information provided by DNSPs. AEMO estimates historical maximum and minimum underlying demand at each DTx (with statistical methods to address gaps), and re-scales the ZSS-level underlying demand trace in the previous step to match. This ensures the DTx-level underlying demand trace has the same load shape but with locally specific characteristics. Load growth factors are computed from the parent ZSS-level underlying demand traces forecasts and applied as the last step to produce DTx-level underlying demand traces forecast.

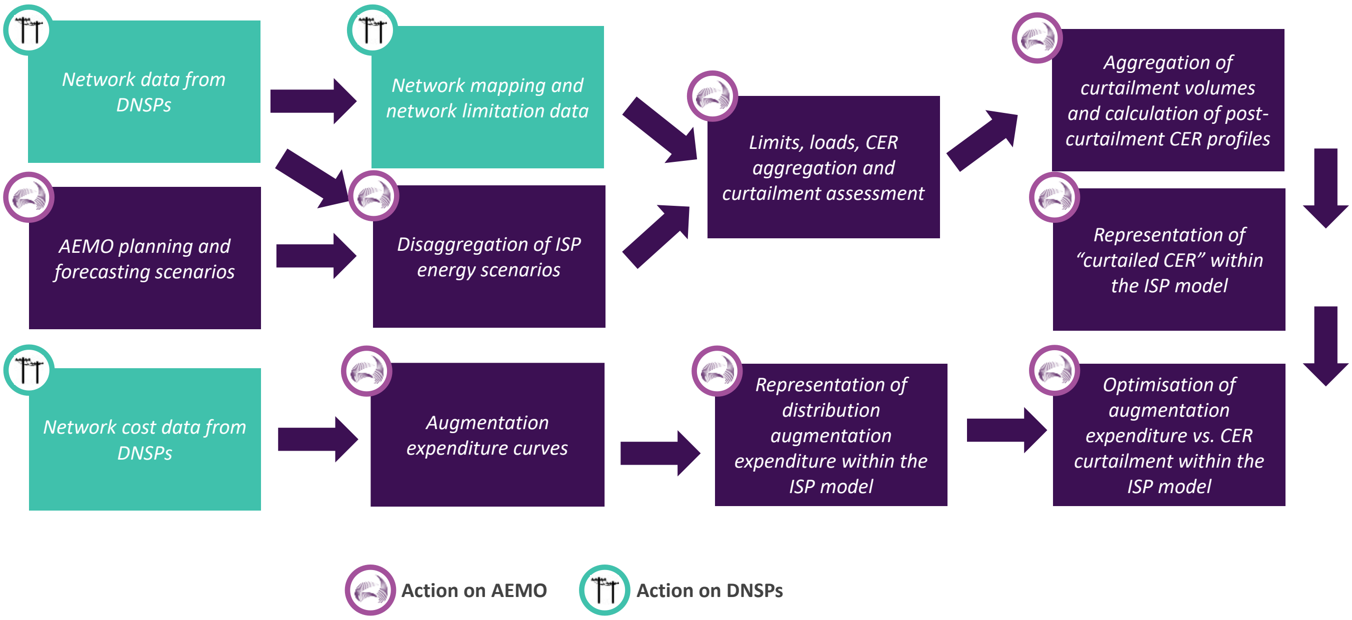
2.12.5 Distribution network data collection

The data requirements and ISP model implications for incorporating opportunities for low voltage connected CER into the ISP market model are significant. For the 2026 ISP, AEMO requires sufficiently comprehensive data from DNSPs to assess both network capabilities and opportunities for CER. The approach to requesting data was consulted with DNSPs, and the following principles were adopted:

- Maximise use of public and readily available internal DNSP data.
- Retain flexibility in the approach to improve sophistication as CER modelling capabilities continue to grow.
- Standardise, where possible, the calculation approach to bring consistency and transparency to how CER is included.
- Ensure the benefit of local CER serving local load is captured.
- Incorporate the development of other distributed resources, noting network limitations regarding operation and investment.

DNSPs were given two options to provide data on their distribution networks – Standard Pathway or Alternate Pathway. Most DNSPs have chosen the Standard Pathway as shown in **Figure 19**. This is a distribution asset data option, providing low voltage substation capacity data (thermal and voltage limits where available) which, when combined with low voltage level load and CER forecasts, can be used to estimate low voltage hosting capacity and opportunities for further CER enablement.

Figure 19 Standard Pathway – DNSP asset data collection



The template for DNSP data provision is summarised in **Table 11**. An outline of the network data received from DNSPs is in Section 5.

Table 11 DNSP Standard Pathway asset data template

Table	Field Name	Field ID	Provision
Distribution Sub Capacity	Distribution Substation Site Unique Identifier	D_id	Compulsory
Distribution Sub Capacity	Distribution Substation Site 'Name plate' Capacity (MVA)	D_name_capacity	Compulsory
Distribution Sub Capacity	Distribution Substation Site Available export capacity (MW)	D_export_capacity	Optional
Distribution Sub Hierarchy	Distribution Feeder Identifier	FDR	Optional
Distribution Sub Hierarchy	Zone Substation Identifier	ZS	Optional
Distribution Sub Hierarchy	Sub Transmission Station Identifier	STS	Optional
Distribution Sub Hierarchy	Transmission Node Identifier (TNI)	TNI	Compulsory
Hierarchy Capacity	Available export capacity Distribution Feeder	FDR_export_capacity	Optional
Hierarchy Capacity	Available export capacity Zone Substation	ZS_export_capacity	Optional
Hierarchy Capacity	Available export capacity Sub Transmission Station	STS_export_capacity	Optional
Hierarchy Capacity	Available export capacity Transmission Node Identifier (TNI)	TNI_export_capacity	Optional
Hierarchy Capacity	MV/HV Connected CER Capacity	total_pv_non_lv	Optional
Disaggregation Info	Historic maximum demand	historic	Optional
Disaggregation Info	Historic minimum demand	historic_min	Optional

Table	Field Name	Field ID	Provision
Disaggregation Info	Latitude	lat	Compulsory
Disaggregation Info	Longitude	long	Compulsory
Disaggregation Info	Currently Connected CER Capacity – Rooftop PV Capacity (MW) per Distribution Substation	total_pv	Compulsory
Disaggregation Info	Currently Connected CER Capacity – Total PV Inverter Rating or Site export limit per Distribution Substation	total_site_export	Optional
Capacity Cost	Network Level ID	level_name_ID	Optional
Capacity Cost	Hierarchy Type	level_code	Optional
Capacity Cost	Financial Year	fy_cost	Compulsory
Capacity Cost	Tranche	tranche_cost	Optional
Capacity Cost	CER Export Capacity Cost $/MW	export_cost	Compulsory
Capacity Cost	% Overhead network assets less than 33kV (wires and poles)	OH_MV_cost	Compulsory
Capacity Cost	% Underground network assets less than 33kV (cables)	UG_MV_cost	Compulsory
Capacity Cost	% Distribution substations including transformers	TX_MV_COST	Compulsory
Capacity Cost	% Overhead network assets 33kV and above (wires and towers / poles etc)	OH_HV_cost	Compulsory
Capacity Cost	% Underground network assets 33kV and above (cables, ducts etc)	UG_HV_cost	Compulsory
Capacity Cost	% Zone substations and transformers	TX_HV_cost	Compulsory
Capacity Cost	% Easements	land_cost	Compulsory
Capacity Cost	% Meters	meter_cost	Compulsory
Capacity Cost	% "Other" assets with long lives	other_long_cost	Compulsory
Capacity Cost	% "Other" assets with short lives	other_short_cost	Compulsory

2.12.6 Distribution network low voltage limits and opportunities

The physical arrangement and capability of distribution network infrastructure can create limitations on the aggregate operation of CER. CER operation may be restricted due to factors such as electricity network limitations or power system stability issues. This modelling approach focuses on assessing network limitations that could inhibit aggregate CER operation, with power system operational issues including power system stability considered under separate real time operations processes[89].

The modelling approach disaggregates regional load and forecast CER availability down to the low voltage level, then determines forecast potentially constrained CER output due to limitations on reverse power flow at low voltage assets, and opportunities to augment the distribution network to unlock this potentially constrained CER. These constrained CER outputs are then aggregated progressively back up to the sub-regional level to determine its potential impact. The Standard Pathway methodology is as follows:

1. Assess DNSP data – asset capacity data and mapping data for calculation, historical demand and PV capacity for data quality and consistency.

[89] Information about AEMO's workstreams to address the power system operational impacts of increasing levels of CER and other distributed resources is at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations.

2. Generate load and CER availability forecasts at the low voltage asset level.
3. Utilising thermal and (where available) voltage constraints on the low voltage network, combine these with load and CER availability forecasts to calculate CER output and opportunities to alleviate curtailment. This captures the benefit of local generation meeting end consumer level demand, while not overestimating the ability of local generation to supply demand within a larger region without considering the available local network capacity.
4. Calculate any additional CER capacity challenges at the medium voltage (MV) network (where data is available).
5. Calculate any additional CER capacity challenges at the high voltage (HV) network (where data is available).
6. Aggregate CER output to the Transmission Network Identifier (TNI) level.
7. Aggregate CER output to sub-region.
8. Review and calibration.

Section 2.12.9 outlines how the CER outputs and distribution network augmentations will be represented in modelling constraint equations

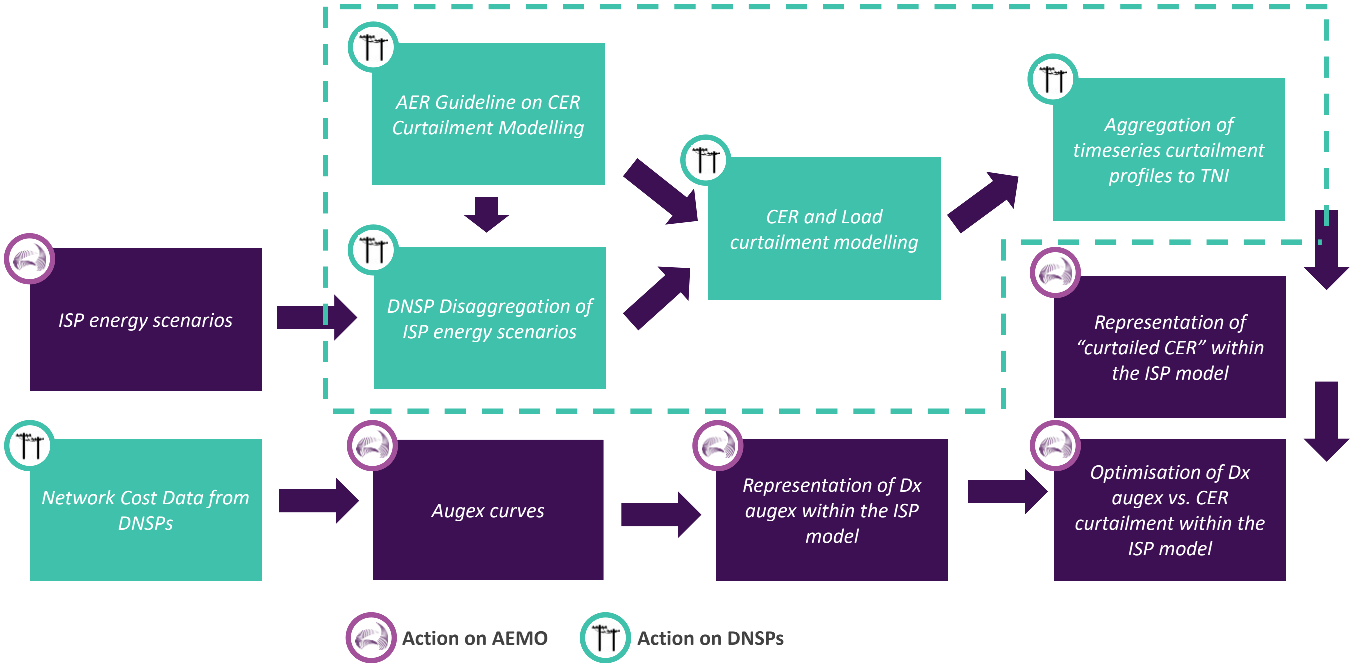
2.12.7 The Alternate Pathway for network data

The Alternate Pathway was developed for where a DNSP has detailed power flow modelling of their distribution network that is likely to produce high-quality outputs. It involves the DNSP undertaking this modelling to provide transmission node-level forecasts of CER outputs as an input to the modelling process (step #6 in the methodology outlined above) and shown in **Figure 20**.

The Alternate Pathway is subject to a set of criteria which is to ensure significant modelling capability and alignment with AEMO forecasts:

- Ability to utilise AEMO forecasts – ISP and IASR.
- Capability to provide network limits and resulting CER output values for the BAU or 'base case' option, where the base case is defined with alignment with TNSP criteria.
- Ability to meet turnaround times.
- Capability to provide 30-minute network limit values (megawatt hours [MWh]) aggregated to the TNI level for the forecast period.
- Demonstrate that the DNSP time series representation is sufficiently aligned with AEMO's for all the above, within an acceptable margin of error.

Figure 20 Alternate Pathway – Detailed power flow modelling



2.12.8 Distribution network CER augmentation costs

Where there is existing capacity in distribution networks, the modelling approach assumes this capacity is utilised before any further augmentation is required. Beyond currently available capacity, given the potential for distribution networks to limit aggregate CER operation, the 2026 ISP will consider the cost of distribution network augmentation to alleviate these limits. DNSPs are responsible for maintaining safety, reliability and power quality on their network and will consider a range of feasible options to meet an identified need of unlocking more opportunities for CER. AEMO has segmented the types of solutions and options DNSPs are likely to deploy as follows:

- **Tranche 1** – use existing distribution network capacity to facilitate the operation of existing aggregate CER operation with no additional distribution network augmentation.
- **Tranche 2** – undertake targeted voltage management optimisations primarily to manage elevated voltages from CER export. These would include investments in voltage management technologies[90] such as dynamic export limits, useful and relatively low cost tools to mitigate CER-driven network operation challenges.
- **Tranche 3** – once targeted enhancements have been exhausted, consider whether more costly network augmentation expansions may be required. These allow increasing CER uptake and operation at the consumer level by expanding physical network capacity in order toreduce curtailment.

To best align with the AER CBA Guidelines, AEMO has defined the 'base case' CER export capacity of the distribution network before augmentation for the ISP modelling purposes as being the network as it is today plus approved capital expenditure from:

[90] Voltage management and compliance is important as DNSPs often face challenges with voltage rise due to high CER penetration, particularly rooftop solar.

- the most recent AER Determination for the relevant DNSP (usually the Final Determination, but Draft Determination if the Final is not yet available) for either the current or upcoming regulatory period, and
- any relevant contingent project decisions.

All other future capital expenditure is excluded, as this is to be estimated by the ISP market model. More detail on the augmentation capital expenditure data received and what will be incorporated into the ISP market model is outlined in Section 5.1.2.

Consultation questions

7. Is the planned approach for calculating opportunities for CER and associated distribution network costs reasonable? Noting time and data constraints, are there other factors AEMO could reasonably consider?

2.12.9 Constraints for ISP market model application

The ISP model will incorporate additional complexity in considering distribution network opportunities to enable more CER and other distributed resources. Calculating constraints on CER is typically a complex relationship between local generation, load and network topology, which will be simplified for model ingestion. At a minimum, this will capture potential curtailment on the CER connected at the low voltage level due to thermal constraints at distribution substations. At a maximum, this could capture potential curtailment on all CER connected to the distribution network due to either thermal constraints on reverse power flow or voltage constraints. The underlying CER capacity forecast as determined by AEMO is the starting point.

AEMO then determines, based on existing limits using DNSP data, a refined unconstrained CER output forecast and resultant opportunities for further CER enablement (see Section 2.12.2). The output from this analysis is a range of decision points to balance investment between distribution network augmentation and larger-scale alternatives.

The key distribution network inputs for the ISP market model are constraint equations which will consider:

- an aggregated value for all DNSP voltage levels
- a variable value for $/MW which will depend on MW of alleviation required, and
- a cost to increase distribution network capacity from a given base year.

This will be modelled as a net transfer capacity from the distribution network to the ISP sub-region in the market model. A simplified constraint object for each sub-region is included in the ISP market model[91] to determine optimised distribution costs. The illustrative formulation of each constraint for each sub-region is as follows:

$$
\begin{aligned}
Gen_{PV} - Underlying\ Demand + Discharge_{pass.st.} - Charge_{pass.st.} + Discharge_{pass.EV} - Charge_{pass.EV} \\
+ c_1(Discharge_{Coord.st.} + Discharge_{V2G}) - (Est.\ Charge_{coord.st.} + Est.\ Charge_{V2G}) \\
\leq Limit + Augmentation
\end{aligned}
$$

Please see **Table 12** below for definitions of these terms.

[91] Where there are multiple DNSPs within a defined sub-region in the ISP, AEMO may prepare individual DNSP constraint equations.

Table 12 ISP market model constraint equation inputs

Term	Type	Units	Temporal granularity	Definition
$\boldsymbol{Gen_{PV}}$	Dispatch variable optimised in ISP model	MW	Interval level	Half-hourly generation for PV embedded in the low voltage network in the sub-region.
$\boldsymbol{Underlying\ Demand}$	Fixed input	MW	Interval level	Half-hourly underlying demand in the low voltage network in the sub-region
$\boldsymbol{Discharge_{pass.st.}}$	Fixed Input	MW	Interval level	Half-hourly generation from passive storage in the low voltage network in the sub-region
$\boldsymbol{Charge_{pass.st.}}$	Fixed Input	MW	Interval level	Half-hourly load from passive storage in the low voltage network in the sub-region
$\boldsymbol{Discharge_{pass.EV}}$	Fixed Input	MW	Interval level	Half-hourly generation from passive EV in the low voltage network in the sub-region
$\boldsymbol{Charge_{pass.EV}}$	Fixed Input	MW	Interval level	Half-hourly load from passive EV in the low voltage network in the sub-region
$\boldsymbol{Discharge_{Coord.st.}}$	Dispatch variable optimised in ISP model	MW	Interval level	Half-hourly generation from wholesale price-responsive storage in the low voltage network in the sub-region
$\boldsymbol{Discharge_{V2G}}$	Dispatch variable optimised in ISP model	MW	Interval level	Half-hourly generation from V2G in the low voltage network in the sub-region
$\boldsymbol{c_1}$	Fixed Input	MW	Interval level	Defines the ratio of additional MW of CER generation to additional curtailment of CER generation in the low voltage network. Value determined through the curtailment study by calculating CER curtailment with and without generation from price-responsive CER.
$\boldsymbol{Est.\ Charge_{coord.st.}}$	Fixed Input	MW	Interval level	Estimated half-hourly load from wholesale price-responsive storage in the low voltage network in the sub-region
$\boldsymbol{Est.Charge_{V2G}}$	Fixed Input	MW	Interval level	Estimated half-hourly load from wholesale price-responsive V2G in the low voltage network in the sub-region
$\boldsymbol{Limit}$	Fixed Input	MW	Interval Level	Limitation of the low voltage network to export/accommodate generation from low voltage connected CER. This is set at a value which would result, in the absence of distribution augmentation, the curtailment volume determined via the curtailment study.
$\boldsymbol{Augmentation}$	Build decision optimised in ISP model	MW	Annual	Capacity of distribution augmentation to alleviate curtailment of low voltage connected CER generation

Note: All terms are provided across the ISP horizon out to 2054-55, and are provided for each of the AEMO forecasting and planning scenarios.

2.12.10 Other distributed resources

The term ‘other distributed resources’ in the 2026 ISP refers to any generation or storage resources that are in the distribution network, in front of the meter and below 30 MW in capacity. While CER assets are mostly installed by households, other distributed resources tend to be owned by larger customers and are spread much less uniformly across distribution networks.

The further development of other distributed resources may be limited by additional factors, since they are larger and occupy more space relative to CER. Other distributed resources would require land, zoning, and network connections to host these new generation and storage assets on commercial terms.

Similar to the constraint equations developed for CER, the key distribution network inputs for the ISP market model to consider other distribution resources are:

- Network limits – values for this are to be based on DNSP annual Regulatory Information Notices (RIN) data, tested against the limited network capacity data provided for the medium voltage level by DNSPs. This may be set as the maximum historical demand for that asset or point in the network, consistent with observations of when DNSPs have previously chosen to augment assets.
- Network augmentation costs (excluding connection costs) – values for this are also to be based on DNSP RIN data, tested against the limited cost data provided for the medium voltage level by DNSPs.
- Generation and storage connection costs and other technical parameters such as capacity factors – AEMO is sourcing this from Aurecon, and has published the Aurecon report for consultation alongside the Draft 2025 *Electricity Network Options Report*.

Modelling approach

The inputs above will be combined to prepare separate sub-regional constraints for other distributed resources (or alternatively at the per-DNSP level if this is considered more appropriate). This will be prepared directly as a PLEXOS constraint, without the curtailment calculation which is being done for CER.

Similar to CER constraints, AEMO is proposing to formulate a constraint for other distributed resources for each sub-region:

$$Gen_{\text{Distributed PV without CER}} + (Discharge_{\text{Distributed storage}} - Charge_{\text{Distributed storage}}) - Underlying\ demand_{\text{Commercial and residential}} \\ \leq Distribution\ network\ capability + Distribution\ network\ augmentation$$

where:

- $Gen_{\text{Distributed PV without CER}}$ represents generation from distributed PV generation build candidates.
- $Discharge_{\text{Distributed storage}}$ and $Charge_{\text{Distributed storage}}$ represent the discharge and charge of distributed storage build candidates.
- $Underlying\ demand_{\text{Commercial and residential}}$ represents underlying commercial and residential loads connected to the medium voltage network.
- $Distribution\ network\ capability$ reflects the existing ability for the distribution network to support these distributed resources for each sub-region.
- $Distribution\ network\ augmentation$ reflects the increase on the distribution network capability to support these distributed resources.

Outputs for publication in the 2026 ISP

AEMO will incorporate the constraints in the Draft 2026 ISP modelling, and will advise on the outcomes in the Draft 2026 ISP.

Consultation questions

8. Is the planned modelling approach reasonable for the uptake of other distributed resources? Noting time and data constraints, are there other factors AEMO and DNSPs could reasonably consider?

3 Flow paths

Flow paths are a feature of power system networks, representing the main transmission pathways over which bulk energy is shipped. They are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the network to load centres. Flow paths change as new interconnection is developed, or as a result of shifting large amounts of generation into new areas (such as in the case of major REZ development).

This section outlines network augmentation options to increase the transfer capability of flow paths in the ISP. In general, flow paths represent the movement of power between the sub-regions in the ISP model. The following information is presented for each augmentation option:

- A description of the option.
- The expected increase in transfer capacity.
- The project cost, including the class of the estimate and associated accuracy.
- The project lead time.
- An overview of characteristics which are key cost drivers.

Many of the augmentation options included in this section are either undergoing a RIT-T or other regulatory process. Where available, transfer limits and cost estimates of these augmentation options were sourced from the relevant TNSPs and jurisdictional bodies.

For committed and anticipated transmission augmentation projects, which are already underway for delivery, only the reference scope and expected increase in transfer capacity is provided, per the latest Transmission Augmentation Information workbook[92]. For ISP modelling purposes, committed and anticipated projects are assumed to be underway for delivery and are not reconsidered from a timing or costs and benefits perspective.

Section 3 provides the following flow path information:

- A conceptual map of the flow path options between sub-regions for the 2026 ISP (**Figure 21**).
- A legend and explanation of tables (Section 3.1).
- Central Queensland to Northern Queensland (Section 3.2).
- Central Queensland to Gladstone Grid (Section 3.3).
- Southern Queensland to Central Queensland (Section 3.4).
- Northern New South Wales to Southern Queensland (Section 3.5).
- Central New South Wales to Northern New South Wales (Section 3.6).
- Central New South Wales to Sydney, Newcastle and Wollongong (Section 3.7).
- Southern New South Wales to Central New South Wales (Section 3.8).

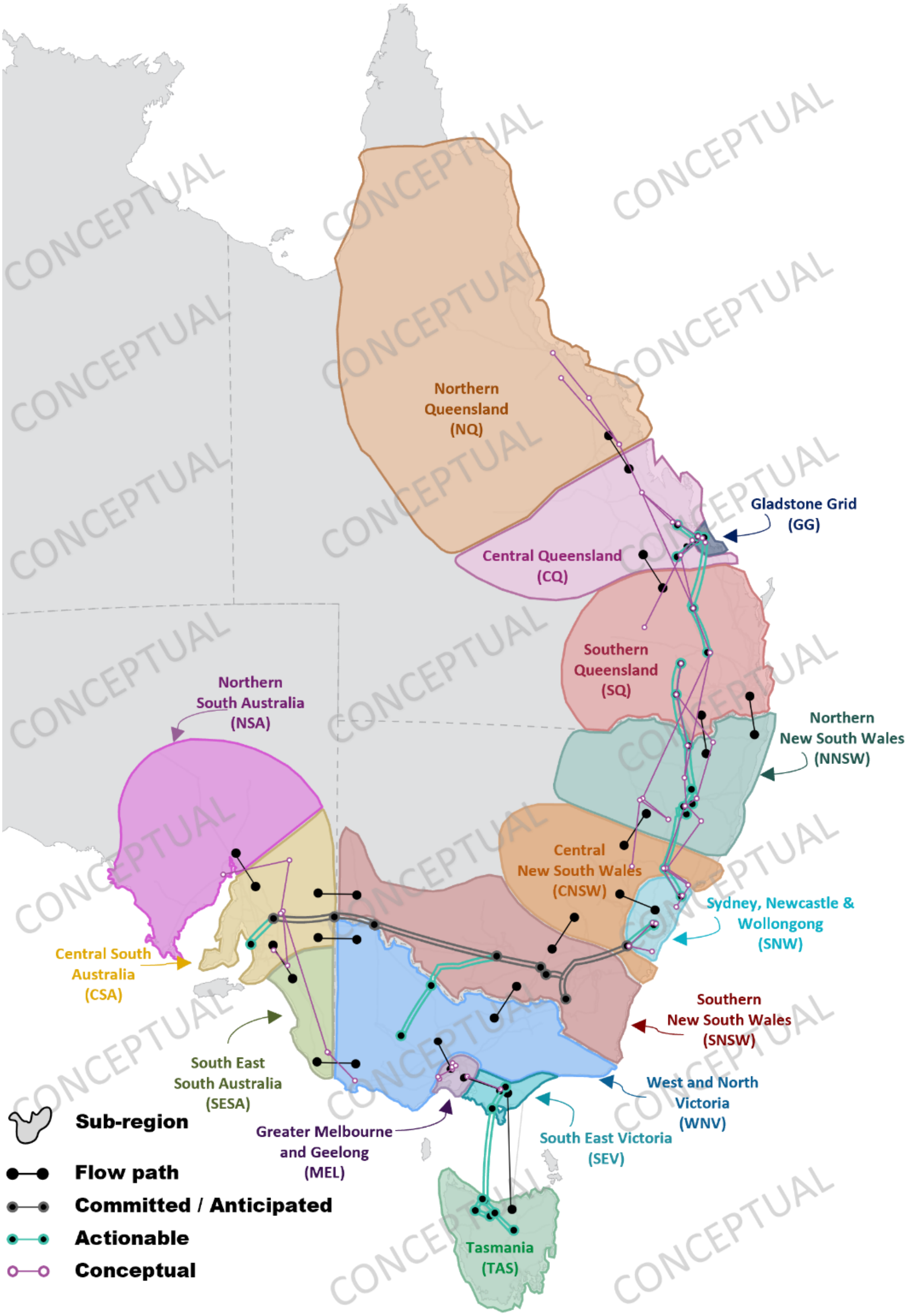
[92] AEMO. Transmission Augmentation Information, December 2024. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

- Southern New South Wales to Central South Australia (Section 3.9).
- West and North Victoria to Southern New South Wales (Section 3.10).
- Greater Melbourne and Geelong to West and North Victoria (Section 3.11).
- South East Victoria to Greater Melbourne and Geelong (Section 3.12).
- Tasmania to South East Victoria (Section 3.13).
- West and North Victoria to South East South Australia (Section 3.14).
- South East South Australia to Central South Australia (Section 3.15).
- Central South Australia to Northern South Australia (Section 3.16).

Consultation questions

9. Do stakeholders have any feedback on the proposed augmentation options for the flow paths in the NEM?
10. Do stakeholders have any proposed additional or alternative network options for the flow paths in the NEM, that should be considered for the final 2025 *Electricity Network Options Report*?
11. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the flow paths.

Figure 21 Conceptual map of flow path options for Draft 2025 *Electricity Network Options Report*



3.1 Legend and explanation of tables

The tables in Section 3 provide an overview of the characteristics of each network development option for flow paths. The following template explains the criteria and terminology used in the tables.

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td colspan="2">A brief description of the existing network is provided (for example, network capacity, projects to increase capacity, findings from the 2024 ISP).</td></tr>
<tr><th colspan="2">Existing network capability</th></tr>
<tr><td colspan="2">For flow paths, this is the approximate maximum forward and reverse flow capability between the regions or sub-regions. These capabilities are represented by nominal transfer capacity when there are no transmission network outages in the local area, allowing for N-1 credible contingencies. The capacity is sourced from recent historical data.
AEMO’s convention for the forward direction of flow paths follow mostly a northerly direction relative to Tasmania and is consistent with the naming of interconnectors (starting from Tasmania to South East Victoria and ending in Central Queensland to Northern Queensland). The reverse direction is the opposite of forward direction.
The limit is the notional maximum transfer limit at the time of “Summer 10% probability of exceedance (POE) demand” (referred to as ‘peak demand’), “Summer Typical”, and “Winter Reference” in the importing region or sub-region, as outlined in the ISP Methodology. The figure quoted is the minimum of the following required limits: transmission asset thermal capacity; voltage stability; transient stability; oscillatory stability; and system strength and inertia.</td></tr>
<tr><th colspan="2">Augmentation options – these include the conceptual design, capability, cost and timing for flow path augmentation options</th></tr>
<tr><td>Additional network capacity (MW)</td><td>This is the additional network transfer capacity for each of the identified options and based on power system studies undertaken by AEMO or TNSPs. For flow paths the direction of power flow is stated.</td></tr>
<tr><td>Cost</td><td>The costs are based on 2024 figures in ($ million). All cost estimates are indicative and prepared using AEMO’s Transmission Cost Database, except for projects currently progressing through the RIT-T (or another regulatory process) or where preparatory activities were required in the 2022 ISP or 2024 ISP. Cost estimates for projects which are currently progressing through the RIT-T (or another regulatory process), or where preparatory activities were required in the 2022 ISP or 2024 ISP, are sourced from the relevant TNSP or NEM jurisdictional body.
Costs shown in this report are rounded to two significant figures for readability. Non-rounded costs from the Transmission Cost Database, TNSPs or jurisdictional bodies will be used in the ISP modelling, and will be documented in the 2025 IASR Workbook.</td></tr>
<tr><td>Cost classification</td><td>This is based on either AEMO’s Transmission Cost Database or TNSPs’ cost estimates information based on the AACE Cost Estimate Classification System as referenced in Section 2.1.</td></tr>
<tr><td>Lead time</td><td>Lead times represent the likely minimum time for service from the date of publication of the final 2026 ISP. The lead time includes regulatory justification and approval, relevant community engagement and planning approvals, procurement, construction, commissioning, and inter-network testing. Lead times are categorised as short (3-5 years), medium (6-7 years), or long (beyond 7 years).
Some additional terms used in ISP documentation to refer to time taken to deliver a transmission project are:
• Earliest in-service date (EISD). The EISD of a project is the earliest date the project can be completed – that is, the addition of the project lead time to the release date of the relevant ISP.
• Project proponent’s timing. Proponent’s timing is the delivery date advised by transmission project proponents for projects that have previously been found actionable in the ISP. This delivery date falls within a project’s actionable window as defined in the ISP Methodology, and is informed by the project development activities undertaken to progress the project.</td></tr>
<tr><th colspan="2">Adjustment factors and risk – notes the adjustment factors, known risks and unknown risks applied to the option, for those estimates which were developed with the Transmission Cost Database.</th></tr>
<tr><td colspan="2">Adjustment factors:
• Location (urban, regional and remote).
• Greenfield/brownfield (greenfield, brownfield and partly brownfield) – greenfield is chosen unless otherwise specified.
• Terrain (flat/farmland, mountainous and hilly/undulating).
• Project network element size (transmission line length, project size).
• Delivery timeframe (optimum, tight, long).
• Contract delivery model (engineering, procure and construct [EPC] contract, design and construct [D&C] contract) – EPC contract is chosen unless otherwise specified.
• Proportion of environmentally sensitive areas (None, 25%, 50%, 75% and 100%).</td></tr>
</table>

• Location wind loading zones (cyclone and non-cyclone regions) – non-cyclone region is chosen unless otherwise specified. • Jurisdiction + Land (state and Rural Bank defined sub-region[93] + Land use 'desert, scrub, grazing and developed area')
Known risk: where the risks are identified but ultimate value is not known. There are nine known risk factors: • Compulsory acquisition (business as usual [BAU], low and high). • Cultural heritage (BAU, medium and high). • Environmental offset risks (BAU, low, high and very high). • Geotechnical findings (BAU, low and high). • Macroeconomic influence (BAU, increased uncertainty and heightened uncertainty). • Market activity (BAU, tight and excess capacity). • Outage restrictions (BAU, low and high). • Project complexity (BAU, partly complex and highly complex). • Weather delays (BAU, low and high).
Unknown risk: where the risk has not been identified but industry experience indicates these could occur: • Scope and technology (Class 5b, Class 5a and Class 4). • Productivity and labour cost (Class 5b, Class 5a and Class 4). • Plant procurement cost (Class 5b, Class 5a and Class 4). • Project overhead (Class 5b, Class 5a and Class 4).

[93] Rural Bank. Australian Farmland Values. 2022. At https://www.ruralbank.com.au/siteassets/_documents/publications/flv/afv-national-2022.pdf.

3.2 Central Queensland (CQ) to Northern Queensland (NQ)

Summary

Following joint planning with Powerlink and consultation in the Draft 2025 IASR, the flow path boundary has been amended to help better model limitations between Nebo and Broadsound (previously between Strathmore-Ross). This resulted in no change to CQ – NQ forward capability compared to the 2024 ISP. These limits were determined with the inclusion of a minor Strathmore to Ross line upgrade.

Options to expand the flow path include updated Queensland SuperGrid North options from Powerlink, under the Queensland Energy and Jobs Plan (QEJP) and the Queensland SuperGrid Infrastructure Blueprint[94], that will enable more renewable generation in REZ Q1, Q2 and Q4.

Map

Existing network capability

The current network was designed to facilitate the transmission of power from CQ to support the load in NQ. As a result, the Central and North Queensland sub-regions can only support up to 2,500 MW of generation across the four REZs in Northern Queensland, depending on the level of storage in the sub-region.

From CQ to NQ, maximum transfer capability is 1,200 MW at peak demand, summer typical levels and 1,400 MW at winter reference periods. From NQ to CQ, maximum transfer capability is 1,440 MW at peak demand, summer typical levels and 1,910 MW at winter reference periods. The maximum transfer capability is limited by thermal ratings and voltage stability for the loss of CQ or NQ transmission network elements.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 275 kV double-circuit line from Ross to Strathmore to Nebo, initially switching one side only Pre-requisite: Assume BAU line refit of 275 kV and 132 kV network between Bouldercombe-Nebo-Strathmore-Ross	Forward: 1,100 Reverse: 1,100 REZ: NQ1: 680	1,790 Class 5b(±50%)	335	Long: (10 years)
Option 2: • 500 kV substation works at Mulgrave (near Townsville 500 kV established as part of CopperString 2032 project) • A new 500 kV substation at locality of northern part of CQ (around 27 km south of Broadsound) • A new 500 kV substation at locality of southern part of NQ (around 80 km south of Nebo) • A new 500 kV double-circuit steel tower (DCST) line from CQ (west of Gladstone) to northern CQ substation • A new 500 kV DCST line from northern CQ to southern NQ substations • A new 500 kV DCST line from southern NQ substation to Mulgrave substation • 2 x 500/275 kV 1,500 MVA transformers at northern CQ and southern NQ substations • Cut-in 275 kV circuits between Stanwell and Broadsound to northern CQ substation and between Broadsound and Nebo to southern NQ substation • Special protection scheme for transfer limit increase (similar to virtual transmission line) with the cost of this Network Service Agreement (NSA) excluded	Forward: 3,000 Reverse: 3,000 REZ: NQ1: 3,000	5,239 Class 5b(±50%)	623	Long: (10 years)

[94] See the Queensland SuperGrid Blueprint for more details, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

Pre-requisite: SQ-CQ Option 3 (QEJP) and Q2 CopperString 2032 Project				
Option 3: • String the 2nd circuit between Stanwell and Broadsound 275 kV Pre-requisite: None	Forward: 350 Reverse: 110 REZ: CQ1: 600	203 Class 5b(±50%)	0	Short: (4 years)
Option 4: • A new 275 kV high-capacity double-circuit line between Bouldercombe and Broadsound • A new 275 kV high-capacity double-circuit line between Broadsound and Nebo • Decommission the existing single circuits Bouldercombe-Broadsound (#820), Bouldercombe-Nebo (#821) and Broadsound-Nebo (#834). Pre-requisite: None	Forward: 1,300 Reverse: 660 REZ: CQ1: 1,600	500[95] Class 5 (+100/-50%)	307	Long: (7 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b
Option 4	Cost estimate provided by Powerlink.	

95 This is the net cost, provided by Powerlink. AEMO (National Planner) will undertake joint planning with Powerlink to confirm what cost treatment would be appropriate for the ISP cost benefit analysis assessment, and may update for the final 2025 *Electricity Network Options Report* accordingly.

3.3 Central Queensland (CQ) to Gladstone Grid (GG)

Summary

Following the retirement or reduced generation from Gladstone Power Station and increased generation in North and Central Queensland, the transmission network supplying the Gladstone area will be constrained. As a result, forecast demand at Boyne Island, Calliope River, Larcom Creek and Raglan substations cannot be supplied. If major industrial loads are electrified, or if large hydrogen projects progress, there is a potential for a material shift in the supply-demand balance in the Gladstone area.

The Gladstone Grid Reinforcement project was an actionable Queensland project in the 2024 ISP. This project is progressing under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.

In the 2024 ISP, AEMO identified the Gladstone Grid Reinforcement project as an actionable Queensland project. The updated options include outcomes of Powerlink's development of the project through the Gladstone Priority Transmission Investment framework[96] to increase thermal capability of transmission lines to supply loads following retirement of generators in Gladstone and increased generation from North and Central Queensland.

Map

Existing network capability

The maximum power transfer capability is influenced by the amount of generation dispatch within northern and central Queensland, particularly at Gladstone. This limit is influenced by the thermal capacity of the Calvale–Wurdong, Bouldercombe–Calliope River, Bouldercombe–Raglan, Raglan-Larcom Creek, Larcom Creek–Calliope River or Calliope River–Wurdong 275 kV circuits.

• With typical generation output from Stanwell and Callide, CQ to GG maximum transfer capability is 700 MW at peak demand and summer typical levels, and 1,050 MW at winter reference condition.
• In the reverse direction, GG to CQ maximum transfer capability is 750 MW at peak demand and summer typical levels and approximately 1,100 MW at winter reference periods.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 275 kV high-capacity double-circuit line between Calvale and Calliope River • Rebuild Larcom Creek to Bouldercombe 275 kV high-capacity double-circuit line • Rebuild Calliope River to Larcom Creek 275 kV high-capacity double-circuit line • A new (third) 275/132 kV transformer at Calliope River • Retain the existing Bouldercombe - Calliope River 275 kV line (#812) until the rebuild of Calliope River to Larcom Creek (retire #812 after completion of project) • New 2 x synchronous condensers at Wurdong substation including a tee of Calliope River - Gin Gin 275 kV line (# 814) into Wurdong • New 200 MVAr capacitor bank at Calliope River and 200 MVAr capacitor bank at Larcom Creek • Install power flow controllers at Wurdong substation on Calvale to Wurdong 275 kV line Pre-requisite: None	Forward: 2,600 Reverse: 500	2,057[97] Class 5a(±30%)	160	Short: (5 years)

[96] At https://www.energyandclimate.qld.gov.au/energy/energy-system-planning/priority-investments.

[97] Powerlink has provided a cost estimate for this project as part of their ongoing consideration of options for this flow path.

Option 2: • A new 275 kV high-capacity double-circuit line between Calvale and Calliope River • Establish Gladstone West (CQ) 275 kV substation • Rebuild Bouldercombe – Calliope River (#812) as Larcom Creek to Bouldercombe 275 kV high-capacity double-circuit line and retain Gladstone West – Calliope River (retire line section between Bouldercombe and Gladstone West) • Cut-ins to the Calliope River to Calvale 275 kV circuits and the Bouldercombe to Larcom Creek 275 kV circuits at Gladstone West substation • A new (third) 275/132 kV transformer at Calliope River • New 2 x synchronous condensers at Gladstone West substation • A new 200 MVAr capacitor bank at Calliope River, 200 MVAr capacitor bank at Larcom Creek, and 150 MVAr bus reactor at Gladstone West substations • Install power flow controller at Wurdong substation on Calvale to Wurdong 275 kV line Pre-requisite: None	Forward: 2,600 Reverse: 500	1,812 Class 5a(±30%) [98]	146	Short: (3 years)
Option 3: • Rebuild Calliope River to Larcom Creek 275 kV high-capacity double-circuit line • Decommission the section of Line 812 between Gladstone West and Calliope River. Pre-requisite: CQ-GG Option 2	Forward: 600 Reverse: 0	176 Class 5b(±50%)	15	Medium: (6 years)
Option 4: • Rebuild Calliope River to Wurdong 275 kV line (#818) as high-capacity double-circuit line Pre-requisite: CQ-GG Option 1 or CQ-GG Option 2	Forward: 550 Reverse: 1,950	187 Class 5b(±50%)	17	Medium: (6 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Cost estimate provided by Powerlink	
Option 2	Cost estimate provided by Powerlink	
Option 3	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Grazing Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Grazing Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b

[98] This $2024 cost estimate from Powerlink does not include contingencies, escalation or synchronous condenser costs. An update will be provided by Powerlink for the final *Electricity Network Options Report*.

3.4 Southern Queensland (SQ) to Central Queensland (CQ)

Summary

Queensland SuperGrid South project is Stage 2 of the Queensland Energy and Jobs Plan in line with Queensland SuperGrid Infrastructure Blueprint[99]. This project involves new 500 kV transmission lines to connect Borumba pumped hydro energy storage into Central Queensland. This project was identified as an actionable Queensland project in the 2024 ISP and is progressing under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.

In the 2020 ISP, AEMO required Powerlink to complete preparatory activities to increase transfer capability from CQ to SQ. In the 2022 ISP, this project was referred as 'Central to Southern Queensland' as a future ISP project. Since the 2022 ISP, the Queensland Energy and Jobs Plan was unveiled, and a new option for connecting CQ and SQ was proposed for the 2024 ISP called the Queensland SuperGrid South. This option was selected in the optimal development path in the 2024 ISP. The SuperGrid South also provides the required transmission capacity to allow the anticipated Borumba pumped hydro project to connect into the NEM (QEJP Stage 1).

Map

Existing network capability

From CQ to SQ, maximum transfer capability is approximately 2,100 MW. This capability is applicable in peak demand, summer typical, and winter reference periods.

The maximum power transfer from CQ to SQ grid section is limited by transient or voltage stability following a Calvale to Halys 275 kV circuit contingency.

From SQ to CQ, maximum transfer capability is 1,100 MW at peak demand, summer typical levels and at winter reference periods. This assumes Powerlink establishes a new 3.5 km double circuit line from Blackwall to Karana Downs allowing dedicated double circuit connections from Blackwall to Rocklea and Blackwall to South Pine. Following these works, the maximum transfer capability from SQ to CQ is limited by thermal capacity of the Palmwoods – South Pine 275 kV line following a credible contingency.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 275 kV double-circuit line between Calvale and Wandoan South • 275 kV line shunt reactors at both ends of Calvale to Wandoan South 275 kV circuits Pre-requisite: None	Forward: 900 Reverse: 900	1,280 Class 5b(±50%)	247	Long: (9 years)
Option 2: • Mid-point switching substation (Auburn River) on the existing Calvale to Halys 275 kV double-circuit line Pre-requisite: None	Forward: 0 Reverse: 300	58 Class 5b(±50%)	0	Short: (5 years)
Option 3: • A new 500 kV double circuit line between mid-point (Auburn River) and Calvale substations, operating at 275 kV. • A new 500 kV double circuit line between mid-point (Auburn River) and Halys substations, operating at 275 kV. • A new 500 kV double circuit line between Calvale and Gladstone West (CQ) 275 kV substations, operating at 275 kV	Forward: 2,800 Reverse: 1,400	3,076 Class 5b(±50%)	366	Long: (10 years)

[99] See the Queensland SuperGrid Blueprint for more details, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

Pre-requisite: SQ-CQ Option 2, SWQLD1 Option 5 and CQ-GG Option 2				
Option 4: • Non-network option – virtual transmission line option with a 300 MW energy storage system north of Calvale and south of Halys Pre-requisite: None	Forward: 300 Reverse: 300	Non-network augmentation	0	Short: (3 years)
Option 5: • New 500 kV double-circuit line between Halys and Auburn River substations • New 500 kV double-circuit line between Auburn River and Gladstone West substations • Establish 500 KV Halys substation with 3 x 500/275 kV 1,500 MVA transformers • New 500 kV substation west of Gladstone (CQ 500 kV substation) with 3 x 500/275 kV 1,500 MVA transformers • Establish 500 kV substation at Auburn River with 2 x 500/275kV 1,500 MVA transformers • New dynamic reactive support at Gladstone West (CQ) substation Pre-requisite: SQ-CQ Option 2 and CQ-GG Option 2	Forward: 3,150 Reverse: 1,900	3,643 Class 5b(±50%)	331	Long: (10 years)
Option 6: • New 500 kV Halys substation with 3 x 500/275 kV 1,500 MVA transformers • New 500 kV substations west of Gladstone (CQ 500 kV substation with 3 x 500/275 kV 1,500 MVA transformers • New 500 kV substation at Auburn River with 2 x 500/275 kV 1,500 MVA transformers • Raise the double-circuit line between Halys and Auburn River substations to 500 kV operation. • Raise the double-circuit line between Auburn River and Gladstone West substations to 500 kV operation • New dynamic reactive support at Gladstone (CQ) west substation Pre-requisite: SQ-CQ Option 3	Forward: 350 Reverse: 500	785 Class 5b(±50%)	0	Long: (10 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Tight Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - South - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Tight Project network element size: Below 5 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - South - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Tight Project network element size: 100 to 200km/# of total Bays 16 - 20 Jurisdiction + Land use: QLD - South - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 4	Non-network option not costed	
Option 5	Delivery timetable: Tight Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: QLD - South - Scrub/QLD - Central - Scrub Location (regional/distance factors): Remote	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 6	Delivery timetable: Tight Project network element size: # of total Bays 16 - 20 Jurisdiction + Land use: QLD - South - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b

3.5 Northern New South Wales (NNSW) to Southern Queensland (SQ)

Summary

The Northern New South Wales (NNSW) and Southern Queensland (SQ) corridor represents a portion of the network which forms part of the QNI. Development options on this corridor include the northern sections of proposed QNI Augmentations.

A project to increase the transfer capacity of the existing QNI (referred as 'QNI Minor') has been completed. The QNI Minor project which increases the transfer capacity of the existing QNI has been commissioned and inter-network testing is at the final hold point stages. The QNI Minor project continues to look for opportunities to undertake the testing.

An additional new interconnection between Queensland and New South Wales (QNI Connect) would increase transfer capacity between Queensland and New South Wales to share renewable energy and firming services between regions. Powerlink and Transgrid completed preparatory activities[100] for QNI Connect 500 kV and 330 kV options in June 2023, and Transgrid provided an addendum to the preparatory activities in March 2024[101].

QNI Connect was identified an actionable ISP project in the 2024 ISP. These updated options have been provided by Transgrid and Powerlink through joint planning and are being modelled as part of the Regulatory Investment Test for Transmission.

Map

Existing network capability

Transfer capabilities are modelled with the QNI Minor upgrade now in service, which is nearing the final stages of inter-network testing to release the designed maximum capacity.

NNSW to SQ expected transfer capability is 950 MW at peak demand, summer typical and winter reference periods.

In the reverse direction, SQ to NNSW expected transfer capability is 1,450 MW at peak, summer typical and winter reference periods. The maximum transfer capacity is limited by the thermal capacity of Sapphire-Armidale 330 kV line for an outage of Dumaresq-Armidale 330 kV line.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 330 kV single-circuit line from New England REZ North Hub (Hub 10) to Dumaresq to Bulli Creek to Braemar. • A new 330/275 kV transformer at Braemar. • 330 kV line shunt reactor at New England REZ North Hub, Dumaresq, Bulli Creek, and Braemar for the New England North Hub – Dumaresq - Bulli Creek - Braemar 330 kV circuits. Pre-requisite: CNSW-NNSW Option 1, N2 Option 1	Forward: 730 Reverse: 900	1,893 Class 5 (±50%)[102]	460[103]	Short: (5 years)

[100] See Preparatory Activities page, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[101] See Supporting materials for 2023 page, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[102] Cost estimate is provided by Powerlink and Transgrid as part of their preparatory activities, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[103] This new easement length will be refined for the final 2025 *Electricity Network Options Report*.

Option 1a[104]: • A new 330/132 kV substation near Swan Vale with 2 x 375 MVA 330/132 kV transformers • Demolition of Armidale to Glen Innes 132 kV line • A new 330 kV high capacity double-circuit line from New England REZ North Hub 10 to Armidale to Halys. • A new 330 kV substation at Halys with 330/275 kV transformers • 60 MVAr 330 kV line shunt reactors at New England REZ North Hub and Halys. Pre-requisite: CNSW-NNSW Option 1, N2 Option 1	Forward: TBC Reverse: TBC	TBC	TBC	Medium: (6 years)
Option 2: (ISP candidate option) • A new 330 kV double-circuit line from New England North Hub (Hub 10) to Dumaresq to Bulli Creek to Braemar. • New 330/275 kV transformers at Braemar. • 330 kV Line shunt reactors at New England North Hub, Dumaresq, Bulli Creek, and Braemar, for the 330 kV lines between North Hub and Braemar (via Dumaresq and Bulli Creek). Pre-requisite: CNSW-NNSW Option 1, N2 Option 1	Forward: 1,260 Reverse: 1,700	2823[105] (Total project cost) Class 5b(±50%) (NSW)	460[103]	Medium: (7 years)
Option 2a: • Construct new 330/132 kV substation at Swan Vale with 2 x 375 MVA 330/132 kV transformers • Demolition of Armidale to Glen Innes 132 kV line • A new 500 kV double-circuit line from New England REZ North Hub (Hub 10) to Halys • A new 500/275 kV transformer at Halys • 150 MVAr 500 kV line shunt reactors at New England REZ North Hub, and Halys on each circuit Pre-requisite: CNSW-NNSW Option 1, N2 Option 1 CNSW-NNSW Option 2 SQ-CQ Option 5 or 6 (Queensland SuperGrid South - QEJP Stage 2)	Forward: 2,570 Reverse: 2,460	4,007 Class 5b(±50%)	460[103]	Medium: (7 years)
Option 3: • A Virtual Transmission Line option with a 200 MW energy storage system south of Armidale and north of Braemar. Pre-requisite: None	Forward: 200 Reverse: 200	Non-network augmentation	0	Short: (3 years)
Option 4: • A 2,000 MW HVDC bi-pole overhead transmission between a new substation in North West New South Wales (locality of Boggabri) and Halys. • A new 2,000 HVDC bipole converter station in North West New South Wales • A new 2,000 HVDC bipole converter station in locality of Halys. • AC network connection between HVDC converter station and 275 kV substation in Halys. • AC network connection between HVDC converter station and ac network in in NWNSW REZ. • A new 330 kV line between locality of Boggabri and Tamworth. Pre-requisite: CNSW-NNSW Option 5	Forward: 1,800 Reverse: 2,000	8,819 Class 5b(±50%)	600	Medium: (7 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Cost estimate provided by Powerlink and Transgrid.	
Option 1a	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 16 - 20 Jurisdiction + Land use: NSW - Northern -	Known Risks: BAU Unknown Risk: Class 5b

[104] AEMO (National Planner) will undertake joint planning with Powerlink and Transgrid to refine the scope and cost of this option in the final 2025 *Electricity Network Options Report.*

[105] This total project cost estimate includes both the northern and southern portions, and includes unknown risk allowance. AEMO (National Planner) will undertake joint planning with Powerlink and Transgrid to incorporate an updated cost estimate in the final 2025 *Electricity Network Options Report*.

	Grazing/QLD - South - Grazing Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	
Option 2	Queensland cost estimate provided by Powerlink. AEMO has estimated the New South Wales cost with the TCD using the same settings as Option 1a.	
Option 2a	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Non-network option not costed	
Option 4	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b

3.7 Central New South Wales (CNSW) to Northern New South Wales (NNSW)

Summary

The Central New South Wales (CNSW) to Northern New South Wales (NNSW) corridor represents a portion of the network which forms part of New South Wales - Queensland Interconnector (QNI). Development options on this corridor include access of increased renewable generation and energy storage in New England REZ to supply the major load centres in New South Wales as well as the southern sections of proposed QNI upgrades.

The New England REZ Network Infrastructure Project was an actionable New South Wales project in the 2024 ISP. This project is progressing under the Electricity Infrastructure Investment Act 2020 (NSW). EnergyCo has advised that it will be completed in two parts – Part 1 (CNSW-NNSW Option 1 and REZ N2 Option 1) by July 2032, and Part 2 (CNSW-NNSW Option 2) by January 2034.

Map

Existing network capability

The Queensland – New South Wales Interconnector (QNI) Minor project, which increases the transfer capacity of the existing QNI, has been commissioned and inter-network testing is in progress.

The CNSW to NNSW maximum transfer capability is 910 MW at peak demand, summer typical and winter reference periods. The maximum transfer capability is limited by voltage stability for loss of Kogan Creek generator.

The NNSW to CNSW maximum transfer capability is 930 MW at peak demand and summer typical periods and 1,025 MW at winter reference period. The maximum transfer capability is limited by thermal capacity of Armidale–Tamworth 330 kV lines following a credible contingency.

The Waratah Super Battery (WSB) with System Integrity Protection Scheme (SIPS), which increases the transfer capacity between NNSW to CNSW when paired with selected generators, is expected to be completed by August 2025. During the five-year contract period of the WSB with SIPS and paired generation, the NNSW to CNSW transfer capability is expected to increase by 300 MW in one direction only.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 500 kV DCST line between Central (Hub 5) and Bayswater with Quad Orange conductor. • A new Central (Hub 5) 500/330 kV substation with 3 x 500/330/33 kV 1,500 MVA transformers and cut into existing 330 kV lines between Tamworth and Armidale. • A new 4 x 330 kV 340 MVA phase shifting transformers at Central (Hub 5). • 4 x 500 kV 150 MVAr line shunt reactors (in total) are required for 500kV DCST line between Central Hub 5 and Bayswater. Pre-requisite: None	Forward: 2,400 Reverse: 2,400[106] REZ: N2: 2,400	2,509 Class 5b(±50%)	217	Medium: (6 years)
Option 2: • Expand Northern (Hub 10) switching station to 500/330kV substation with 3 x 500/330/33kV 1,500 MVA transformers and cut into the existing 330 kV lines between Armidale to Sapphire/Dumaresq • Expand Central South (Hub 1) switching station to 500/330 kV substation with 3 x 500/330/33 kV 1,500 MVA transformers. • A new 500 kV DCST from Central South (Hub 1) to Bayswater with Quad Orange conductor • Operate line between Central Hub 5 and Central South Hub 1 from 330 kV to 500 kV. • Operate line between Central Hub 5 and Northern Hub 10 from 330 kV to 500 kV.	Forward: 3,600 Reverse: 3,600 REZ: N2: 3,600	2,173 Class 5b(±50%)	215	Long: (8 years)

[106] AEMO assumes a symmetrical uplift in both directions and is dependent on the location of future generation.

• 4 x 500 kV 150 MVAr line shunt reactors (in total) for 500 kV double-circuit line between Central South (Hub 1) and Bayswater. Pre-requisite: CNSW-NNSW Option 1 REZ N2 Option 1.				
Option 4: • A new 2,000 MW bi-pole HVDC transmission system between locality Bayswater and locality of Hub 5. • A new 330 kV double-circuit line from a new substation in locality of Hub 5 to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Hub 5. Pre-requisite: None	Forward: 1,750 Reverse: 2,000 REZ: N2: 2,000	3,683 Class 5b(±50%)	239	Medium: (6 years)
Option 5: • A new 2,000 MW bi-pole HVDC transmission system between locality of Wollar and locality of Boggabri. • A new 330 kV AC line between locality of Boggabri and Tamworth. Pre-requisite: NNSW-SQ Option 4.	Forward: 1,750 Reverse: 2,000 REZ: N1: 2,000	5,023 Class 5b(±50%)	307	Medium: (6 years)
Option 6: • Expand Bayswater Hub to accommodate 1,900 MVAr capacitor banks and 1,300 MVAr dynamic reactive plant (SVC/STATCOM) at 330 kV Pre-requisite: CNSW-NNSW Option 1 N2 Option 1 CNSW-NNSW Option 2	Forward: 1,500[105] Reverse: TBC[107]	436 Class 5b(±50%)	0	Long: (9 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Tight Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: NSW - Northern - Grazing Location (regional/distance factors): Remote	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Central - Grazing/NSW - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Northern - Grazing/NSW - Central - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 5	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Northern - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 6	Delivery timetable: Optimum Project network element size: # of total Bays 6 - 10 Jurisdiction + Land use: NSW - Central - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

[107] The limits will be joint planned with EnergyCo for the final *Electricity Network Options Report*.

3.8 Central New South Wales (CNSW) to Sydney, Newcastle and Wollongong (SNW)

Summary

The transmission network in the Sydney, Newcastle, and Wollongong (SNW) area was originally designed to connect large coal-fired generators in the Hunter Valley to supply the SNW load centres. When these coal-fired generators retire, the network has insufficient capability to supply SNW load centres from generators located outside of the Hunter Valley. Both the Sydney Ring North and Sydney Ring South projects increase the transfer capacity into the SNW load centres.

The Hunter Transmission Project (Sydney Ring North Project[108]) is classified as a 'priority transmission infrastructure project'[109] under the Electricity Infrastructure Investment Act 2020 (NSW). This project was identified as an actionable project in the 2022 ISP and 2024 ISP, and is now proceeding as an actionable New South Wales project rather than through the ISP framework.

The Sydney Ring South project was identified as an actionable ISP project in the 2024 ISP. Timing for any need to increase power system capability to support the SNW load centres from the south of New South Wales depends on load distribution and sizing within SNW, as well as power transfer from Southern NSW (SNSW) to Central New South Wales (CNSW), Northern NSW (NNSW) to CNSW and CNSW to SNW. Direction and amount of power transfer on the 500 kV lines between Bannaby and Mt Piper would highly influence timing of the Sydney Ring South project.

Map

Existing network capability

The existing transfer capability varies depending on load and generation distribution within the SNW area, as well as the generation within central NSW (CNSW) and power transfer from northern NSW (NNSW) and southern NSW (SNSW) subregions to CNSW. For better representation of these limitations, the existing transfer capability between CNSW and SNW is separately identified as North and South flow paths:

CNSW-SNW North flow path is assumed to be the sum of flows on Bayswater – Sydney West, Bayswater – Regentville, Liddell – Newcastle, Liddell – Tomago, Wallerawang – Ingleburn and Wallerawang – Sydney South 330 kV lines and Stroud – Brandy Hill, Stroud – Tomago, Hawks Nest tee – Tomago and Singleton – Rothbury 132 kV lines. The maximum transfer capability of the CNSW-SNW North flow path is 4,490 MW at peak demand and summer typical periods, and 4,730 MW at winter reference periods. The maximum northern transfer capability is limited by several 330 kV lines and the most limiting elements are Liddell-Newcastle and Liddell-Tomago 330 kV lines.
The CNSW-SNW North transfer capability will increase by 0.12 MW for 1 MW (12%) of increased Eraring generation.

CNSW-SNW South flow path is assumed to be the sum of flows on Bannaby – Sydney West, Marulan – Dapto, Marulan – Avon and Kangaroo Valley – Dapto 330 kV lines. The maximum transfer capability of CNSW-SNW South flow path is 2,540 MW at peak demand and summer typical, and 2,720 MW at winter reference periods. The maximum southern transfer capability is limited by several 330 kV lines and the most limiting element is Bannaby-Sydney West 330 kV line.

[108] The Sydney Ring North project is named the Hunter Transmission Project and may include the Waratah Super Battery and related upgrades.

[109] See https://www.energyco.nsw.gov.au/projects/hunter-transmission-project.

It is assumed Tallawarra generation is at zero output in these transfer limit calculations. CNSW-SNW South transfer capability will reduce by 0.51 MW for 1 MW (51%) of increased Tallawarra generation. The Waratah Super Battery (WSB) with System Integrity Protection Scheme (SIPS), which increases the transfer capacity between CNSW to SNW when paired with selected generators, is expected to be completed by August 2025. When enabled during the 5-year contract period, the SIPS will be capable of increasing the transfer capability of the CNSW-SNW North and South flow paths by up to 700 MW and 250 MW, respectively.				
Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Option 1: Sydney Ring Northern 500 kV loop or the Hunter Transmission Project (HTP): • A new 500 kV double-circuit line between Olney substation and Bayswater South substation. • New switching stations at Bayswater South (near Bayswater substation) and Olney (near Eraring substation). • 500 kV connections between Bayswater and Bayswater South substations, and between Eraring and Olney substations. • Two 500/330 kV 1,500 MVA transformers at Eraring substation. •Line reactors on 500 kV transmission lines between Olney and Bayswater South. (Note: When Central West Orana REZ exceeds 3 gigawatts (GW), this option should be considered to transfer this additional generation to SNW). Pre-requisite: None	Forward: 5,000 (This capacity increase for accommodation of additional new generation from North of Bayswater and 2/3 generation from Central West NSW) Reverse: N/A REZ: N10: 2,000	1,238 Class 5b(±50%)	110	Short: (2 years[92])
Option 2: Establish a new South Creek Substation • Establish a 500/330 kV South Creek substation cutting into 330 kV lines Sydney West - Bayswater(#32), Sydney West - Regentville (#38) and Bannaby - Sydney West (#39) and 500 kV lines Eraring - Kemps creek (#5A1, #5A2), with two 1,500 MVA 500/330 kV transformers. • Rebuild approximately 7 km of existing single circuit 330 kV Bannaby - Sydney West (#39) between South Creek and Sydney West as double circuit, stringing with high temperature low sag (HTLS) conductor. • One 330 kV transmission line switch bay at Sydney West. Pre-requisite: CNSW-SNW Option 1	Forward: 0 MW (This option improves power flow sharing between the northern and southern segments of the CNSW-SNW flow paths. This allows more generation to be transferred to Sydney from SNSW. Please note this option is subject to AEMO modelling and assessment for the final *Electricity Network Options Report*.) Reverse: N/A	338 Class 5b(±50%)	0	Short: (4 years)
Option 2d: (ISP candidate option) Power flow control on the 330 kV network	Forward: 0 (This option improves power flow sharing between the	221[110] Class 5b(±50%)	0	Short: (2 years)

[110] This is the $2023 cost of the power flow controller option for Sydney Ring South provided by Transgrid. AEMO (National Planner) will undertake joint planning with Transgrid to incorporate an updated cost estimate in the final 2025 *Electricity Network Options Report*.

• Install power flow control devices in the 330 kV network supplying Sydney from the south, which may include the establishment of a new switching station in greater southwest Sydney. (The scope, feasibility and timing of this option is under review by Transgrid for inclusion in the final 2025 *Electricity Network Options Report*.) Pre-requisite: CNSW-SNW Option 1	northern and southern segments of the CNSW-SNW flow paths. This allows more generation to be transferred to Sydney from SNSW.) Reverse: N/A			
Option 3: Sydney Ring South initially operated at 330 kV Stage 1: • Establish a new 330 kV South Creek switching station cutting into 330 kV Sydney West – Bayswater (#32), Sydney West - Regentville (#38) and Bannaby - Sydney West (#39). • Double circuit 330 kV transmission line built to a 500 kV design between Bannaby substation and the new South Creek switching station along a new 70 m wide greenfield easement. • Two new 330 kV transmission line switch bays at Bannaby. • Rebuild 7 km of existing single circuit 330 kV between South Creek and Sydney West as double circuit, including stringing with high temperature low sag (HTLS) conductor. • Re-conductor 7 km of existing double circuit 330 kV lines 32 and 38 with high temperature low sag (HTLS) conductor between South Creek and Sydney West. • One new 330 kV transmission line switch bay at Sydney West. Stage 2: • Upgrade South Creek to a 330/500 kV substation cutting into 500 kV Eraring - Kemps Creek (#5A1, #5A2) with three 1,500 MVA 500/330 kV transformers. • Two new 500 kV transmission line switch bays at Bannaby. • Re-termination of 500 kV designed transmission lines at Bannaby and South Creek. • 4x 120 MVAr line shunt reactors on the 500kv lines between Bannaby and South Creek Pre-requisite: None	Forward: Stage 1: 1,300 MW Stage 2: 2,300 MW Please note this option is subject to AEMO modelling and assessment for the final *Electricity Network Options Report*. Reverse: None REZ: N11 + N12: 2,000	1,265 Class 5b(±50%)	131	Long: (7 years)
Option 4: Staged 500 kV Sydney Ring South Stage 1: • Establish a 500/330 kV South Creek substation cutting into 330 kV Sydney West - Bayswater(#32), Sydney West - Regentville (#38) and Bannaby - Sydney West (#39) and 500 kV Eraring - Kemps Creek (#5A1, #5A2) with two 1,500 MVA 500/330 kV transformers. • Rebuild 7 km of existing single circuit 330 kV between South Creek and Sydney West as double circuit, including stringing with high temperature low sag (HTLS) conductor. • One new 330 kV transmission line switch bay at Sydney West. Stage 2: • Upgrade the South Creek 330/500 kV substation with a third 500/330 kV transformer. • Two new 500 kV transmission line switch bays at South Creek. • Two new 500 kV transmission line switch bays at Bannaby. • Double circuit 500 kV transmission line (114 km) between Bannaby substation and the new South Creek switching station along a new 70 m wide greenfield easement. • Re-conductor 7 km of existing double circuit 330 kV lines 32 and 38 with high temperature low sag (HTLS) conductor between South Creek and Sydney West. • 4 x 120 MVAr line shunt reactors on the 500 kV lines between Bannaby and South Creek Pre-requisite: None	Forward: Stage 1: 0 MW (Stage 1 improves power flow sharing between the northern and southern segments of the CNSW-SNW flow paths. This allows more generation to be transferred to Sydney from SNSW.) Stage 2: 3,600 MW Please note this option is subject to AEMO modelling and assessment for the final *Electricity Network Options Report*. Reverse: None REZ: N11 + N12: 2,000	1,241 Class 5b(±50%)	131	Long: (7 years)

Option H-Newcastle: To provide access to port near Newcastle: • Three new 500 kV lines from Bayswater to Newcastle. • Four new 500/330 kV transformers at Newcastle. • Line shunt reactors at each of the new 500 kV lines. Pre-requisite: None	Forward: 5,000 Reverse: 5,000 REZ: N10: 5,000	1,633 Class 5b(±50%)	180	Medium: (7 years)
Option H-Dapto: To provide access to port near Dapto: • Three new 500 kV lines from Bannaby to Dapto. • Four new 500/330 kV transformers at Dapto. • Line shunt reactors at each of the new 500 kV lines. Pre-requisite: None	Forward: 5,000 Reverse: 5,000 REZ: N11 + N12: 5,000	1,437 Class 5b(±50%)	154	Medium: (7 years)
Option 6a: • A new 500 kV double-circuit line between substation near Eraring and Bayswater substation. • Two 500/330 kV 1,500 MVA transformers either at Eraring substation or new substation near Eraring • Two 500/330 kV 1,500 MVA transformers at Kemps Creek • 1 x 330 kV SCST line between Vales Pt and Eraring • 1 x 330 kV SCST line between Vales Pt and Munmorah • Thermal upgrade for Vales Pt – Eraring (#24) and Newcastle – Vales Point (#92) 330 kV lines • 1 x 330 kV SCST line between Liddell – Newcastle • 1 x 330 kV SCST line between Eraring – Newcastle Pre-requisite: CNSW-SNW Option 1	Forward: 4,400 (This capacity increase is for accommodation of additional new generation from NNSW and CNSW) Reverse: N/A	2,110 Class 5b(±50%)	354	Medium: (6 years)
Option 6b: • A new 500 kV double-circuit line between Eraring and Bayswater substation. • A new 500/330 kV substation in locality of Richmond Vale with two 500/330 kV 1,500 MVA transformers, cut in Newcastle-Liddell (#81) and Tomago-Liddell (#82) 330 kV lines, and a new 5 km DCST cutting-in between Tomago-Newcastle 330 kV line (#95). • Two 500/330 kV 1,500 MVA transformers (bringing the total to four transformers) near Eraring. • 1 x 330 kV single-circuit line between Vales Pt and new Eraring. • 1 x 330 kV single-circuit line between Vales Pt and Munmorah. • Thermal upgrade for 330 kV lines Vales Pt – Eraring (#24) and Newcastle – Vales Point (#92). • 1 x 330 kV single-circuit line between locality of Richmond Vale – Newcastle. • Line reactors on 500 kV transmission lines. Pre-requisite: CNSW-SNW Option 1	Forward: 4,400 (This capacity increase is for accommodation of additional new generation from NNSW and CNSW) Reverse: N/A	1,656 Class 5b(±50%)	238	Medium: (6 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Urban	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 2d	Cost estimates provided by Transgrid	
Option 3	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Central - Developed	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b

	Location (regional/distance factors): Regional/Urban	
Option 4	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Outage restrictions: High Others: BAU Unknown Risk: Class 5b
H-Newcastle	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b
H-Dapto	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 16 - 20 Jurisdiction + Land use: NSW - Central - Scrub/NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 6a	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 6b	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Outage restrictions: High Others: BAU Unknown Risk: Class 5b

3.9 Southern New South Wales (SNSW) to Central New South Wales (CNSW)

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The transmission network between Southern New South Wales (SNSW) and Central New South Wales (CNSW) 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.

HumeLink[111] is an anticipated project that reinforces the southern New South Wales network, connecting the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect to Bannaby, and is expected to be completed by December 2026.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The maximum transfer capability from SNSW to CNSW is 2,700 MW at peak demand and summer typical and 2,950 MW winter reference periods. The maximum transfer capability is limited by thermal capacity of Collector – Marulan 330 kV lines following a credible contingency.

The maximum transfer capability from CNSW to SNSW is 2,320 MW at peak demand and summer typical and, 2,590 MW at winter reference periods. The maximum transfer capability is limited by thermal capacity of Yass–Canberra or Marulan–Yass or Gullen Range–Bannaby 330 kV lines following a credible contingency.

The Waratah Super Battery (WSB) with System Integrity Protection Scheme (SIPS), which increases the transfer capacity between SNSW to CNSW when paired with selected generators, is expected to be completed by August 2025. When enabled during the five-year contract period, the SNSW to CNSW transfer capability is expected to increase by 250 MW in one direction only.

After HumeLink is in service, the transfer capability between SNSW and CNSW will increase by 2,200 MW in both directions.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td>(HumeLink):
• New Gugaa 500/330 kV substation and 330 kV double-circuit connection to the existing Wagga Wagga 330 kV substation.
• Three new 500 kV transmission circuits between:
- Maragle and Bannaby 500 kV substations.
- Maragle and Gugaa 500 kV substations.
- Gugaa and Bannaby 500 kV substations.
• Three 500/330 kV 1,500 MVA transformers at Maragle substation.
• Two 500/330 kV 1,500 MVA transformers at new Gugaa substation.
• 500 kV Line shunt reactors at the ends of Maragle – Bannaby, Maragle – Gugaa and Gugaa – Bannaby 500 kV lines.
• Augmenting the substations at Maragle, Wagga Wagga and Bannaby to accommodate the additional transmission lines and transformers.

Pre-requisite: None</td><td>Forward: 2,200
Reverse: 2,200

REZ: N6 + N7: 2,200</td><td colspan="3">This project is considered to be anticipated and so is not included as an option here.
The scope of the project is listed here for context so that the subsequent options can be understood.</td></tr>
<tr><td>Option 2:
• A 2000 MW bi-pole overhead transmission line from locality of Bannaby to locality of Gugaa.
• A new 2,000 MW bipole converter station in locality of Bannaby.
• A new 2,000 MW bipole converter station in locality of Gugga.</td><td>Forward: 2,000
Reverse: 2,000

REZ: N6: 2,000</td><td>4,826
Class 5b(±50%)</td><td>283</td><td>Long: (9 years)</td></tr>
</table>

[111] See Transgrid's website for project updates https://www.transgrid.com.au/projects-innovation/humelink/.

• AC network connection between new HVDC converter station in the locality of Bannaby and the existing Bannaby 500 kV substation. • AC network connection between HVDC converter station in the locality of Gugga and a future Gugaa 500 kV substation. Pre-requisite: HumeLink				
Option 3: • An additional new 500 kV double-circuit line from Dinawan to Gugaa • An additional new 500 kV double-circuit line from Gugaa to Bannaby. • 4 additional new 500/330/33 kV 1500 MVA transformers at Dinawan. Pre-requisite: HumeLink, VIC-SNSW Option 1 (VNI West), CNSW-SNW Option 2	Forward: 6,000 Reverse: 6,000 REZ: N5+N6: 6,000	3,522 Class 5b(±50%)	450	Long: (9 years)
Option 4: • An additional new 500 kV single-circuit line from Dinawan to Gugaa • An additional new 500 kV single-circuit line from Gugaa to Bannaby. • 2 additional new 500/330/33 kV 1500 MVA transformers at Dinawan. Pre-requisite: HumeLink, VIC-SNSW Option 1 (VNI West), CNSW-SNW Option 2	Forward: 3,000 Reverse: 3,000 REZ: N5+N6: 3,000	2,784 Class 5b(±50%)	450	Long: (9 years)
Option 5: • A new Switching Station near Wondalga at the Y point connecting the 3 x 500 kV HumeLink lines: - Bannaby - Gugaa 500 kV line - Bannaby - Maragle 500 kV line - Gugaa - Maragle 500 kV line Pre-requisite: HumeLink	Forward: 450 Reverse: 450[112]	112 Class 5b(±50%)	0	Short: (3 years)

Adjustment factors and risk

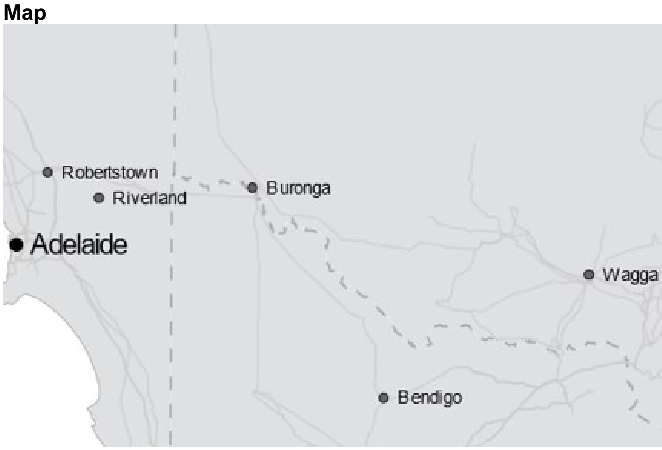
Option	Adjustment factors applied	Known and unknown risks applied
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Southern - Grazing Location (regional/distance factors): Regional	Known Risks: Project complexity: Highly complex Outage restrictions: High Cultural heritage: High Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: NSW - Southern - Grazing Location (regional/distance factors): Regional	Known Risks: Outage restrictions: High Cultural heritage: High Others: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 1 - 5 Jurisdiction + Land use: NSW - Southern - Grazing Location (regional/distance factors): Regional	Known Risks: Outage restrictions: High Cultural heritage: High Others: BAU Unknown Risk: Class 5b
Option 5	Delivery timetable: Optimum Project network element size: Below 5 km/# of total Bays 1 - 5 Jurisdiction + Land use: NSW - Southern - Grazing Location (regional/distance factors): Regional	Known Risks: Outage restrictions: High Others: BAU Unknown Risk: Class 5b

[112] These limits will be joint planned with Transgrid for the final 2025 *Electricity Network Options Report*.

3.10 Southern New South Wales (SNSW) to Central South Australia (CSA)

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>The flow path SNSW-CSA represents the new New South Wales - South Australia interconnector, known as Project EnergyConnect.

Project EnergyConnect is under construction for a new 330 kV interconnector between New South Wales and South Australia. The interconnector runs from Robertstown in South Australia to near Wagga Wagga in New South Wales, via the northernmost section of the transmission network in Victoria. It traverses between east and west, linking the REZs of Riverland, Murray River, and South West New South Wales, providing additional hosting capacity in these REZs.

Project EnergyConnect has been split into two stages, stage 1 connecting Robertstown through Buronga which was completed in late 2024 providing an initial limit of 150 MW between New South Wales and South Australia. Stage 2 is currently underway[113].</td>
<td rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>After the completion of Project Energy Connect Stage 1, the SNSW-CSA interconnector is expected to have a maximum capacity of 150 MW in both directions.

After the completion of Project Energy Connect Stage 2, the SNSW-CSA interconnector is expected to increase to 800 MW in both directions.</td></tr>
</table>

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
No augmentation options proposed				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
No augmentation options proposed		

[113] See Transgrid's website for project updates https://www.transgrid.com.au/projects-innovation/energyconnect/.

3.11 West and North Victoria (WNV) to Southern New South Wales (SNSW)

Summary

The flow path WNV-SNSW represents the Victoria - New South Wales interconnector.

VNI West is a proposed 500 kV interconnector from Bulgana in Victoria to a new substation named Dinawan in southwest New South Wales. The 2022 ISP identified VNI West (via Kerang) as the ISP candidate option in the ODP. Since publication of the 2022 ISP, AEMO Victorian Planning (AVP) and Transgrid have concluded the RIT-T and confirmed option 5A as the preferred option. In May 2023, the Victorian Minister for Energy and Resources used powers under the National Electricity (Victoria) Act 2005 to issue an order that identifies VNI West as a specified augmentation[114]. This option connects Bulgana and Dinawan via a new terminal station near Kerang. This option includes relocation of the Western Renewable Link (WRL) proposed terminal station from north of Ballarat to Bulgana and the uprate of the proposed WRL transmission line from north of Ballarat to Bulgana from 220 kV to 500 kV[115]. VNI West remains as an actionable ISP project, as it was in the 2022 and 2024 ISP.

Map

Existing network capability

Transfer capability of future options has been modelled with VNI Minor upgrade and Victoria SIPS with battery storage in-service for increased transfer capability from Southern New South Wales to Victoria.

Victoria to SNSW maximum transfer capability is 870 MW at peak demand and 1,000 MW at summer typical and winter reference periods. The maximum transfer capability is limited by voltage stability or transient stability limit.

The maximum transfer capability from SNSW to Victoria is 400 MW at peak demand, summer typical and winter reference periods. This is limited by a voltage stability limit. When available, Victoria's SIPS allows the 330 kV lines between South Morang and Murray to operate at a higher thermal capacity for a short period following a critical contingency.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1 - VNI West (Kerang): • A new 500 kV double-circuit overhead line from Bulgana to near Kerang to locality of Dinawan, including series compensation on the line near Kerang. • Upgrade Dinawan - Gugaa double-circuit line from 330 kV to 500 kV operation (lines built at 500 kV as part of Project EnergyConnect) • Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 MVA transformers. •Establish new terminal station near Kerang with two 500/220 kV 1,000 MVA transformers. • 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines near Kerang. • Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain	Forward: 1,935 Reverse: 1,669 REZ: V1: 1,580 V3 (WRL timing): 1,460 V3 (WRL & VNI timing): 200 N5: 900	3,614 Class 4(±30%) ($2023)[116]	438	Short: (3 years)

[114] See https://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S267.pdf.

[115] VNI West Project Assessment Conclusions Report and project updates, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/reports-and-updates/vni-west-pacr-volume-1.pdf?la=en.

[116] This is the 2023 cost of the VNI West Project without Western Renewables Link project, this was calculated from the nominal 2021 dollar value of $3.499 billion presented in the PACR. AEMO (National Planner) will undertake joint planning with Transgrid and AEMO (Victorian Planner) to incorporate an updated cost estimate in the final 2025 Electricity Network Options Report.

contingencies. • 500 kV line shunt reactors at both ends of the three following 500 kV circuits: (i) Bulgana – near Kerang, (ii) near Kerang – Dinawan and (iii) Dinawan – Gugaa. •Two new 500 kV bays and line exits with a total of two 500 kV line shunt reactors at the Bulgana Terminal Station. • Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang. • Approximately 100 MVAr 500 kV switched bus connected reactor at Sydenham. • Rebuilding existing 330 kV single circuit as a double-circuit overhead line from Lower Tumut to Wagga Wagga. • In addition, series compensation or additional power flow controllers would be installed along the Kerang to Bulgana section to reduce impedance on the new 500 kV network and thereby improve network load sharing with, and manage network loading on, the existing 330 kV Victoria – New South Wales Interconnector and the existing 220 kV western Victoria network between Bendigo and Kerang. Work is ongoing to confirm the technical feasibility of this solution. Pre-requisite: Victorian Western Renewables Link and HumeLink				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Cost estimate provided by AEMO (Victorian Planner) and Transgrid	

3.12 Greater Melbourne and Geelong (MEL) to West and North Victoria (WNV)

Summary
The Greater Melbourne and Geelong (MEL) to West and North Victoria (WNV) flow path represents connections between the main load centre of Melbourne and Geelong to the north via South Morang to Dederang and Thomastown to Eildon, and connections to the west via Moorabool, Sydenham, and Bulgana. The 2024 ISP identified a future ISP project in the west (Western Victoria Grid Reinforcement), and this new flow path allows more detailed analysis of this corridor. AEMO Victorian Planning has since published a Project Specification Consultation Report (PSCR)[117] which initiates the public consultation process for this Regulatory Investment Test-Transmission.
Existing network capability
Generation from MEL is not expected to supply WNV (forward direction) at times of high demand periods. MEL to WNV maximum transfer capability is 3,000 MW for cases where Victorian load is between 4,000 MW and 6,000 MW. The maximum transfer capability is limited by the thermal capability of the 220 kV lines between Ballarat and Bendigo. WNV to MEL maximum transfer capability is 2,300 MW at peak demand, 2,550 MW at summer typical and 4,880 MW at winter reference periods. The maximum transfer capability is limited by the thermal capability of the 220 kV lines between Moorabool and Geelong.

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Cut both existing Geelong to Keilor 220 kV lines into Deer Park. • Replace existing Keilor 500/220kV transformers with 1000 MVA units (expected to be completed as part of asset replacement project). • Operate the three Deer Park to Keilor 220kV circuits as normally-open, with supply to Deer Park provided from Geelong. • Install wind monitoring on both existing Geelong to Moorabool 220kV lines and minor interplant replacements to increase rating. Pre-requisite: None	Forward: 800 Reverse: N/A	128 Class 5b (±50%)[118]	0	Short: (5 years)
Option 2: • Cut both existing Geelong to Keilor 220 kV lines into Deer Park. • Replace existing Keilor 500/220kV transformers with 1000 MVA units (expected to be completed as part of asset replacement project). • Operate the three Deer Park to Keilor 220kV circuits as normally-open, with supply to Deer Park provided from Geelong. • Construct 3rd Geelong to Moorabool 220kV line. Pre-requisite: None	Forward: 800 Reverse: N/A	174 Class 5b (±50%)[119]	7	Short: (5 years)
Option 3: • A new 500 kV double circuit line from Moorabool to locality of Truganina. • A new 500 kV single circuit line from locality of Truganina to Sydenham.	Forward: 2000 Reverse: N/A	470 Class 5 (+100/-50%) [VicGrid value subject to	90	Medium: (7 years)

[117] Western Metropolitan Melbourne Reinforcement, at https://aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf?la=en.

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

[119] This is the 2024 cost of Option 2B of the Western Metropolitan Melbourne Reinforcement project presented in the PSCR.

• A new 500 kV substation in locality of Truganina with a cut-in between Moorabool and Sydenham. • Two new 220 kV double circuit lines from locality of Truganina to Deer Park. • Operate the three Deer Park to Keilor 220 kV circuits as normally closed, and operate the three Geelong to Deer Park circuits as normally open. Pre-requisite: MEL-WNV Option 1 or 2		adjustment and risk section notes below]		
Option 4: • Replacement of the existing 330/220 kV transformers at South Morang (H1 and H2) with higher rated units. • One transformer is to be in service and other is to be a hot spare to manage fault levels. • This project is to bring forward asset renewal of 330/220 kV transformers at South Morang. Pre-requisite: None	Forward: 250 (This assumes additional generation from the north) Reverse: N/A	160 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	0	Short: (2 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Estimate provided by AEMO (Victorian Planning)	
Option 2	Estimate provided by AEMO (Victorian Planning)	
Option 3	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 4	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

3.13 South East Victoria (SEV) to Greater Melbourne and Geelong (MEL)

Summary

The South East Victoria (SEV) to the Greater Melbourne and Geelong (MEL) flow path represents connections between the Gippsland region of Victoria to the main load centre of Melbourne and Geelong.

The 2024 ISP identified a future ISP project for the Eastern Grid Reinforcement, and this new flow path allows more detailed analysis of this corridor. AEMO Victorian Planning has since published a Project Specification Consultation Report (PSCR)[120] which initiates the public consultation process for this Regulatory Investment Test-Transmission.

Map

Existing network capability

SEV to MEL maximum transfer capability is 7,100 MW at peak demand, 7,430 MW at summer typical and 8,170 MW at winter reference periods. The maximum transfer capability is limited by the thermal capability of the 220 kV lines between Rowville and Yallourn or Brunswick and Richmond.

The same transfer limits apply in the reverse direction however power is not expected to frequently flow from MEL to SEV since the major load centre is Greater Melbourne and Geelong, represented in the MEL sub-region.

These transfer limits are applicable for the existing network before retirement of Yallourn Power Station. After the retirement of Yallourn Power Station and the implementation of the modified parallel operation mode of Latrobe Valley reconfiguration project being progressed by AEMO Victorian Planning, the forward direction limit is expected to reduce by 1,175 MW for peak demand, 1,560 MW for summer typical and 2,000 MW for winter reference.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Install a third 1000 MVA 500/220kV transformer at Rowville on bus 3-4 group. • Increase line rating of existing Hazelwood/Yallourn – Rowville 220kV (Control scheme and dynamic wind monitoring). Pre-requisite: Post Yallourn power station closure. Latrobe Valley modified parallel mode switching configuration and inter-trip protection scheme to prevent overloads on Hazelwood-Yallourn 220 kV lines or Hazelwood 500/220 kV transformers.	Forward: 1000 Reverse: N/A	35 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	0	Short: (5 years)
Option 2: • Install a third 1000 MVA 500/220kV transformer at Rowville on bus 3-4 group. • Install series impedance on the Hazelwood 500/220 kV transformers. Pre-requisite: Post Yallourn power station closure. Latrobe Valley modified parallel mode switching configuration and inter-trip protection scheme to prevent overloads on Hazelwood-Yallourn 220 kV lines or Hazelwood 500/220 kV transformers.	Forward: 2700 Reverse: N/A	190 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	0	Short: (5 years)
Option 3: • Install 2nd 1000 MVA 500/220kV transformer at Cranbourne. • Transfer existing Rowville 500/220kV A2 transformer from bus group 1-2 to bus 3-4 group. • Increase line rating of existing Hazelwood/Yallourn – Rowville	Forward: 450 Reverse: N/A	35 Class 5 (+100/-50%) [VicGrid value subject to	0	Short: (5 years)

[120] Eastern Victoria Grid Reinforcement, at https://aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf?la=en.

220kV (Control scheme and dynamic wind monitoring). Pre-requisite: Post Yallourn power station closure. Latrobe Valley modified parallel mode switching configuration and inter-trip protection scheme to prevent overloads on Hazelwood-Yallourn 220 kV lines or Hazelwood 500/220 kV transformers.		adjustment and risk section notes below]		
Option 3a: • Install 2nd 1000 MVA 500/220kV transformer at Cranbourne. • Tie in the existing Hazelwood to Rowville 500 kV (No.3) circuit at Cranbourne.	TBC[121]	65 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	0	Short: (5 years)
Option 4: • Install 2nd 1000 MVA 500/220kV transformer at Cranbourne. • Transfer existing Rowville 500/220kV A2 transformer from bus group 1-2 to bus 3-4 group. • Series impedance on the Hazelwood 500/220 kV transformers. Pre-requisite: Post Yallourn power station closure. Latrobe Valley modified parallel mode switching configuration and inter-trip protection scheme to prevent overloads on Hazelwood-Yallourn 220 kV lines or Hazelwood 500/220 kV transformers.	Forward: 2500 Reverse: N/A	190 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	0	Short: (5 years)
Option 5: Install a second Hazelwood to Yallourn 220 kV double circuit line	TBC[133]	110 Class 5 (+100/-50%) [VicGrid value subject to adjustment and risk section notes below]	10	Short: (3 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 2	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 3	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 3a	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 4	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 5	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

[121] These transfer limits will be joint planned with VicGrid for the final 2025 *Electricity Network Options Report*.

3.14 Tasmania (TAS) to South East Victoria (SEV)

Summary

Tasmania and Victoria are connected by one High Voltage Direct Current cable (Basslink).

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

Project Marinus was identified as an actionable ISP project in the 2022 ISP, and confirmed 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)[122], the third report of the RIT-T, was published in June 2021. This RIT-T analysis was updated in May 2024[123].

Map

Existing network capability

The transfer capacity between Tasmania and South East Victoria is limited by the thermal capability of Basslink (HVDC system between Tasmania and Victoria).

Transfer capacity from Tasmania to South East Victoria is limited to 594 MW and from South East Victoria to Tasmania is limited to 478 MW at times of peak demand, summer typical and winter reference periods. Additionally, a seasonally variable daily energy limit of around 10,600 megawatt hours (MWh) per day is applied to maintain gross flows within allowable thermal ratings of the cable.

Additional network upgrades may also be required for the Central Highlands REZ for new generation connecting in the south of the REZ to access the network upgrades associated with Project Marinus. In particular, incremental upgrades associated with the Waddamana to Palmerston network sections are expected.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1 (Project Marinus Stage 1): •A 750 MW monopole HVDC link between Burnie area in Tasmania and Hazelwood area in Victoria. • A new 750 MW HVDC monopole converter station in Burnie area. • A new 750 MW HVDC monopole converter station in Hazelwood area. • A new 220 kV switching station at Heybridge adjacent to the converter station. • A new double-circuit 220 kV transmission line between Sheffield, Heybridge and Burnie • A new 220 kV double-circuit line from Palmerston to Sheffield with	Forward: 750 Reverse: 750[124]	4,810 (Total for Stage 1, $2023) 3,860[125] (HVDC) Class 4 (±30%) 950[126] (HVAC) Class 4 (+30%,-15%)	~90 (underground cable) 0 (HVAC new easement)	Short: (4 years)

[122] TasNetworks. Project Marinus PACR. At https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf.

[123] MarinusLink. RIT-T update report – 2024, at https://www.marinuslink.com.au/rit-t-process/.

[124] The combined transfer limit from VIC to TAS is 978 MW, and from TAS to VIC 1,344 MW. This is based on an assumption that the largest single contingency in Tasmania is limited to 500 MW.

[125] This is the 2024 cost update for the HVDC portion of Project Marinus Stage 1 project. AEMO (National Planner) will undertake joint planning with MarinusLink to incorporate an updated total cost estimate in the final 2025 *Electricity Network Options Report*.

[126] TasNetworks. Project Marinus PACR. At https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf.

decommissioning of the existing single-circuit line. • A new 500 kV connection from converter station in Hazelwood area. • Decommission existing Sheffield – Burnie 220 kV line. Note: HVDC interconnector components are referred to as Marinus Link 1 Pre-requisite: None				
Option 2 (Project Marinus Stage 2): • An additional 750 MW monopole HVDC link between Burnie area in Tasmania and Hazelwood area in Victoria. • An additional new 750 MW HVDC monopole converter station in Burnie area. • An additional new 750 MW HVDC monopole converter station in Hazelwood area. • A new 220 kV switching station at Staverton. • A new double-circuit 220 kV transmission line from Staverton to Burnie via Hampshire • Cut-in both Sheffield-Mersey Forth double-circuit 220 kV lines at Staverton. • Capacity increase of the four Sheffield–Staverton 220 kV transmission circuits. • A new 500 kV connection from converter station in Hazelwood area. Pre-requisite: TAS-SEV Option 1	Forward: 750 Reverse: 750[127]	2,535 (Total for Stage 2, $2023) 2,010[128] (HVDC) Class 4 (±30%) 525[129] (HVAC) Class 4 (+30%,-15%)	0 (underground cable) ~94 (HVAC new easement)	Medium: (6 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Cost estimates provided by Marinuslink and TasNetworks	
Option 2	Cost estimates provided by Marinuslink and TasNetworks	

[127] The combined transfer limit from Victoria to Tasmania is 1,728 MW, and from Tasmania to Victoria 2,094 MW. This is based on an assumption that the largest single contingency in Tasmania is limited to 500 MW.

[128] This is the 2024 cost update for the HVDC portion of Project Marinus Stage 2 project. AEMO (National Planner) will undertake joint planning with MarinusLink to incorporate an updated total cost estimate in the final 2025 *Electricity Network Options Report*.

[129] TasNetworks. Project Marinus PACR. At https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf.

3.15 West and North Victoria (WNV) to South East South Australia (SESA)

Summary

The West and North Victoria (WNV) to South East South Australia (SESA) flow path represents the Victoria – South Australia interconnector through Heywood Terminal Station and South East Substation.

Should a larger amount of load, generation or storage be developed in South Australia, transmission augmentation options for this flow path may be required. These development options would facilitate increased transmission of renewable energy and supply from energy storage in SESA to WNV.

Existing network capability

WNV to SESA maximum transfer capability is 650 MW at peak demand, summer typical and winter reference periods. The maximum transfer capability is limited by a thermal capacity of Heywood-South East 275 kV line or transient stability limit for loss of the largest generator in South Australia or transient stability limit of loss of South East – Tailem Bend 275 kV line.

SESA to WNV maximum transfer capability is 650 MW at peak demand, summer typical and winter reference periods. The maximum transfer capability is limited by an oscillatory stability limit.

After completion of Project Energy Connect Stage 2, WNV-SESA transfer capability is expected to increase by 100 MW in both directions. This flow path is subject to a combined maximum transfer limit of 1,300 MW (WNV to SESA and SNSW-CSA) and 1,450 MW (SESA to WNV and CSA to SNSW).

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 275 kV double-circuit line from a VRE collection node in South East SA (near Krongart) to Heywood terminal station. • 2x1,000 MVA 500/275 kV transformers at Heywood terminal station. • New VRE collection substation in SESA (near Krongart). Pre-requisite: None	Forward: 890 Reverse: 890	781 Class 5b(±50%)	108	Short: (5 years)
Option 2: • A new 500 kV double-circuit line from a VRE collection node in South East SA (near Krongart) to Heywood terminal station. • New VRE collection substation in SESA (near Krongart). • 2x 1500 MVA 500/275 kV transformers at VRE collection terminal station. Pre-requisite: None	Forward: 1,900 Reverse: 1,900	1,138 Class 5b(±50%)	108	Medium: (6 years)
Option 3: • A 1,500 MW HVDC bi-pole overhead transmission line from Heywood to South East SA (near Krongart). • A new 1,500 MW HVDC bipole converter station in locality of Krongart. • A new 1,500 MW HVDC bipole converter station in locality of Heywood. • AC network connection between HVDC converter station and 275 kV substation in the locality of Krogart. • AC network connection between HVDC converter station and 500 kV AC network in Heywood. Pre-requisite: None	Forward: 1,500 Reverse: 1,500	3,139 Class 5b(±50%)	110	Medium: (6 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - South East - Grazing/VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - South East - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - South East - Grazing/VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

3.16 South East South Australia (SESA) to Central South Australia (CSA)

Summary

The South East South Australia (SESA) to Central South Australia (CSA) flow path represents the connection of the load centre at Adelaide to South East South Australia.

Development options on this corridor include access of increased renewable generation and energy storage in South East South Australia REZ to the load centre at Adelaide and to New South Wales through the New South Wales – South Australia interconnector between Bundey and Buronga, known as Project EnergyConnect.

Map

Existing network capability

The existing transfer capability between SESA and CSA is limited by network constraints between South East South Australia and Bundey substations. SESA to CSA maximum transfer capability is 750 MW at peak and summer typical periods and 800 MW at winter reference period. The maximum transfer capability is limited by thermal capacity of the South East -Tailem Bend 275 kV circuit or Tailem Bend - Tungkillo 275 kV for loss of a parallel circuit.

CSA to SESA maximum transfer capability is 790 MW at peak and summer typical periods and 820 MW at winter reference period. The maximum transfer capability is limited by thermal capability of the Tailem Bend - Tungkillo 275 kV circuit for loss of a parallel circuit.

AEMO is joint planning with ElectraNet to refine the existing network capability values ahead of the final 2025 IASR.

The preparatory activities completed by ElectraNet in 2023 looks to address the existing thermal limit of the Tailem Bend–Mobilong 132 kV line on trip of one Tailem Bend–Tungkillo 275 kV line.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: (part of preparatory activities provided by ElectraNet): • String vacant circuit on the 275 kV Tungkillo – Tailem Bend line. Pre-requisite: None	Forward: 120 Reverse: 120	93 Class 5b(±50%)	59	Medium: (6 years)
Option 2: • A new 500 kV double-circuit line from Bundey terminal station to a VRE collection node in South East SA (near Krongart). •2x 1,500 MVA 500/275 kV transformers at Bundey terminal station. • New VRE collection substation in SESA (near Krongart) that connects to the existing network. • 2x 1,500 MVA 500/275 kV transformers at VRE collection substation. Pre-requisite: None	Forward: 1,470 Reverse: 1,470	3,493 Class 5b(±50%)	421	Long: (9 years)
Option 3: • Build a 275 kV double-circuit line from Bundey terminal station to a VRE collection node in South East SA. • New VRE collection terminal station (near Krongart) that connects to the existing network Pre-requisite: None	Forward: 840 Reverse: 840	2,205 Class 5b(±50%)	421	Long: (8 years)
Option 4: • A 1,500 MW HVDC bi-pole overhead transmission line from Bundey to near Krongart. • A new 1,500 MW HVDC bipole converter station in locality of Krongart. • A new 1,500 MW HVDC bipole converter station in locality of Bundey. • AC network connection between HVDC converter station and 275 kV substation in locality of Krongart • AC network connection between HVDC converter station and 275	Forward: 1,500 Reverse: 1,500	4,247 Class 5b(±50%)	420	Long: (8 years)

kV AC network in Bundey. Pre-requisite: None				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - South East - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - South East - Grazing/SA - Adelaide and Fleurieu - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing/SA - South East - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

3.17 Central South Australia (CSA) to Northern South Australia (NSA)

<table>
<tr><td colspan="5">Summary</td></tr>
<tr><td>The Central South Australia (CSA) to Northern South Australia (NSA) flow path connects the load centres near Adelaide and Bundey/Robertstown, with Davenport.

Development options on this corridor include access of increased renewable generation in Mid-North South Australia REZ to meet demand developing at industrial load centres in Northern South Australia and Eyre Peninsula regions.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>The transfer capability in both directions between CSA and NSA is limited by the existing four 275 kV transmission lines from Bungama, Brinkworth, Belalie and Mt Lock to Davenport.

CSA to NSA maximum transfer capability is 1,070 MW at peak demand and summer typical periods and 1,230 MW at winter reference period. This is limited by the thermal capability of the 275 kV line between Bungama and Davenport.

NSA to CSA maximum transfer capability is 1,150 MW at peak demand and summer typical periods and 1,200 MW at winter reference period. This is limited by the thermal capability of the 275 kV line between Brinkworth and Davenport.

AEMO is joint planning with ElectraNet to refine the existing network capability values ahead of the final 2025 IASR.</td></tr>
<tr><td colspan="5">Augmentation options</td></tr>
<tr><td>Description</td><td>Additional network capacity (MW)</td><td>Expected cost ($ million)</td><td>New easement length (km)</td><td>Lead time</td></tr>
<tr><td>Option 1:
• A new 275 kV double-circuit line from Bundey to Yunta to Cultana East
• A new 275 kV substation in locality of Yunta
• A 275 kV connection between locality of Cultana East and Cultana
• A 275 kV switching station in locality of Yunta
• 4x275 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 275 kV lines.
• 4x275 kV 50 MVAr line-connected reactors at each end of Yunta - Cultana East 275 kV lines.
• Two +/-100 MVAr SVCs at Yunta and two +/-100 MVAr SVCs at Cultana East

Pre-requisite: None</td><td>Forward: 845
Reverse: 745

REZ: MN1: TBC</td><td>2,264
Class 5b(±50%)</td><td>434</td><td>Medium: (6 years)</td></tr>
<tr><td>Option 2:
• A new 330 kV double-circuit line from Bundey to Yunta to Cultana East
• A new 330 kV substation in locality of Yunta
• A new 330 kV substation at Cultana East with 3x700 MVA 330/275 kV transformers
• 275 kV connection between locality of Cultana East and Cultana
• 4x330 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 330 kV lines.
• 4x330 kV 50 MVAr line-connected reactors at each end of Yunta - Cultana East 330 kV lines.
• Two +/-100 MVAr SVCs at Yunta and two +/-100 MVAr SVCs at Cultana East

Pre-requisite: None</td><td>Forward: 970
Reverse: 870

REZ: MN1: TBC</td><td>2,358
Class 5b(±50%)</td><td>347</td><td>Medium: (6 years)</td></tr>
<tr><td>Option 3:
• A new 500 kV double-circuit line from Bundey to Yunta to Cultana East.
• A new 500 kV substation at Bundey with 3x1500 MVA 500/330 kV transformers
• A new 500/275 kV substation at Cultana East with 3x1500 MVA</td><td>Forward: 1,220
Reverse: 1,120

REZ: MN1: TBC</td><td>3,295
Class 5b(±50%)</td><td>347</td><td>Long: (8 years)</td></tr>
</table>

500/275 kV transformers • 275 kV connection between locality of Cultana East and Cultana • 4x500 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 500 kV lines. • 4x500 kV 50 MVAr line-connected reactors at each end of Yunta - Cultana East 500 kV lines. • Two +/-100 MVAr dynamic reactive plants at Yunta and two +/-100 MVAr dynamic reactive plants at Cultana East Pre-requisite: None				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: SA - York and North - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing/SA - Eyre Peninsula - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing/SA - Eyre Peninsula - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

4 Renewable energy zones

REZs are areas in the NEM where clusters of large-scale renewable energy can be efficiently developed, promoting economies of scale in high-resource areas, and capturing important benefits from geographic and technological diversity in renewable resources. AEMO's ISP Methodology[130] provides an overview of how AEMO uses REZ augmentation options and costs in the ISP modelling.

Section 4 outlines network augmentation options to increase the transfer capacity[131] of REZs. REZ network augmentations are designed to allow connection of new generation to the existing network and overcome expected network congestion. The following information is presented for each augmentation option:

- A description of the option.
- The expected increase in transfer capacity.
- The project cost, including the class of the estimate and associated accuracy.
- An overview of characteristics which are key cost drivers.

Where network congestion can result due to the combined output from multiple REZs or where there are significant transmission limits that apply to only a subset of generation within a REZ, additional network limits and potential augmentations are provided.

Cost estimates for REZ augmentation options cover the network augmentation to establish the REZ. These costs are distinct from the costs associated with individual generator connections, which are considered in Section 5.

For committed and anticipated transmission augmentation projects, which are already underway for delivery, only the reference scope is provided as per the Transmission Augmentation Information workbook[132] and the expected increase in transfer capacity. For ISP modelling purposes, committed and anticipated projects are assumed to be underway for delivery and are not reconsidered from a timing or costs and benefits perspective.

Section 4 provides the following REZ information:

- A conceptual map of the candidate REZs and network augmentation options for the 2026 ISP (**Figure 22**).
- A legend and explanation of tables (Section 4.1).
- New South Wales REZ augmentation options (Section 4.2).
- Queensland REZ augmentation options (Section 4.3).
- South Australia REZ augmentation options (Section 4.4).
- Tasmania REZ augmentation options (Section 4.5).
- Victoria REZ augmentation options (Section 4.6).

130 AEMO's current ISP Methodology is at https://www.aemo.com.au/consultations/current-and-closed-consultations/isp-methodology. AEMO is also consulting on updates to the ISP Methodology, at https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

131 The "transfer capacity" of a REZ refers to the amount of generation that can exported from a REZ.

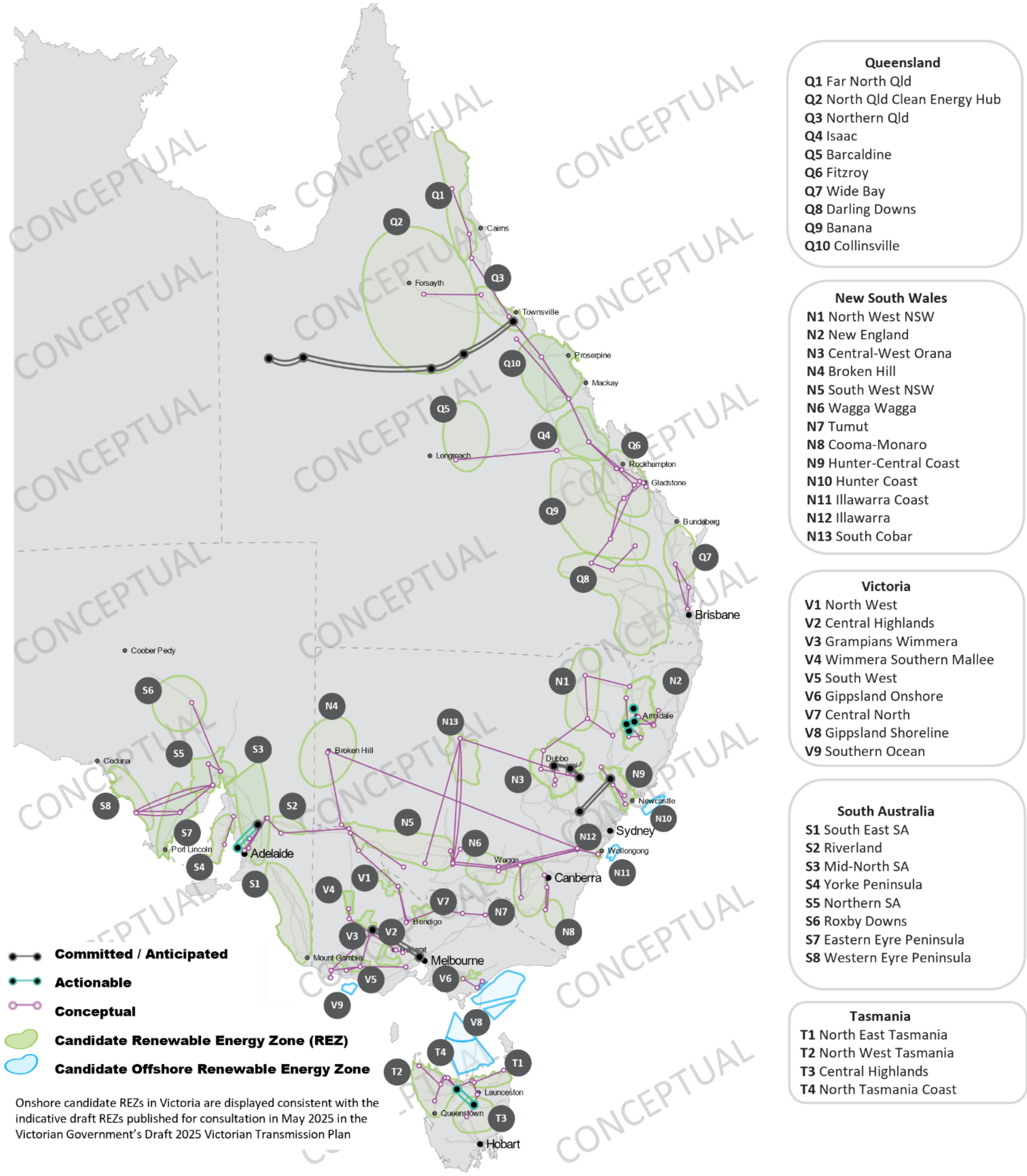
132 AEMO. Transmission Augmentation Information, December 2024. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

- Group constraints applied to the collective output of REZs within each region.

Consultation questions

12. Do stakeholders have any feedback on the proposed augmentation options for the candidate REZs in the NEM?
13. Do stakeholders have any proposed additional or alternative network options for the candidate REZs in the NEM, that should be considered for the final 2025 *Electricity Network Options Report*?
14. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the candidate REZs.

Figure 22 Candidate REZs and REZ augmentation options for Draft 2025 *Electricity Network Options Report*



Onshore candidate REZs in Victoria are displayed consistent with the indicative draft REZs published for consultation in May 2025 in the Victorian Government's Draft 2025 Victorian Transmission Plan

4.1 Legend and explanation of tables

The tables in Section 4 provide an overview of the characteristics of each network development option for renewable energy zones. The following template explains the criteria and terminology used in the tables.

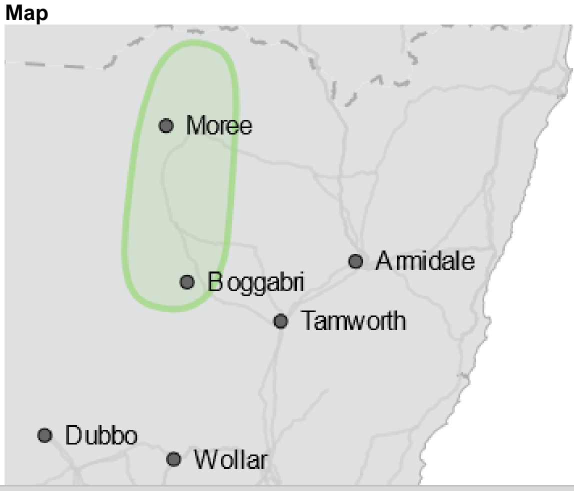
<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td colspan="2">A brief description of the existing network is provided (for example, network capacity, projects to increase capacity, findings from the 2024 ISP).</td></tr>
<tr><th colspan="2">Existing network capability</th></tr>
<tr><td colspan="2">For REZs, this is the capacity of the specific area of the network to allow connection of variable renewable energy (VRE) prior to curtailment being anticipated.</td></tr>
<tr><th colspan="2">Augmentation options – these include the conceptual design, capability, cost and timing for flow path augmentation options</th></tr>
<tr><td>Additional network capacity (MW)</td><td>This is the additional generation output that can be accommodated for each of the identified options and based on power system studies undertaken by AEMO or TNSPs. For REZs, the power flow is often in one direction from the REZ to the network and AEMO will report this export value.
Where the REZ is planned to accommodate additional load (e.g. additional electrolysers or energy storage), AEMO will report the associated import limits for this REZ.</td></tr>
<tr><td>Cost</td><td>The costs are based on 2024 figures in ($ million). All cost estimates are indicative and prepared using AEMO's Transmission Cost Database, except for projects currently progressing through the RIT-T (or another regulatory process) or where preparatory activities were required in the 2022 ISP or 2024 ISP. Cost estimates for projects which are currently progressing through the RIT-T (or another regulatory process), or where preparatory activities were required in the 2022 ISP or 2024 ISP, are sourced from the relevant TNSP or NEM jurisdictional body.
Costs shown in this report are rounded to two significant figures for readability. Non-rounded costs from the Transmission Cost Database, TNSPs or jurisdictional bodies will be used in the ISP modelling, and will be documented in the 2025 IASR Workbook.</td></tr>
<tr><td>Cost classification</td><td>This is based on either AEMO's Transmission Cost Database or TNSPs' cost estimates information based on the AACE Cost Estimate Classification System as referenced in Section 2.1.</td></tr>
<tr><td>Lead time</td><td>Lead times represent the likely minimum time for service from the date of publication of the final 2026 ISP. The lead time includes regulatory justification and approval, relevant community engagement and planning approvals, procurement, construction, commissioning, and inter-network testing. Lead times are categorised as short (3-5 years), medium (6-7 years), or long (beyond 7 years).
• Earliest in-service date (EISD) of a project is the earliest date the project can be completed. AEMO will take advice on the EISD for a project from relevant parties through extensive joint planning with TNSPs and any relevant jurisdictional bodies. Where timelines permit, AEMO will endeavour to consult publicly on EISDs before their application in the ISP modelling.
• Project proponent's timing is the delivery date advised by transmission project proponents for projects that have previously been found actionable. This delivery date falls within a project's actionable window and is informed by the project development activities undertaken to progress the project.</td></tr>
<tr><th colspan="2">Adjustment factors and risk – notes the adjustment factors, known risks and unknown risks applied to the option, for those estimates which were developed with the Transmission Cost Database.</th></tr>
<tr><td colspan="2">Adjustment factors:
• Location (urban, regional and remote).
• Greenfield/brownfield (greenfield, brownfield and partly brownfield) – greenfield is chosen unless otherwise specified.
• Terrain (flat/farmland, mountainous and hilly/undulating).
• Project network element size (transmission line length, project size).
• Delivery timeframe (optimum, tight, long).
• Contract delivery model (EPC contract, D&C contract) – EPC contract is chosen unless otherwise specified.
• Proportion of environmentally sensitive areas (None, 25%, 50%, 75% and 100%).
• Location wind loading zones (cyclone and non-cyclone regions) – non-cyclone region is chosen unless otherwise specified.</td></tr>
</table>

• Jurisdiction + Land (state and Rural Bank defined sub-region [133]+ Land use 'desert, scrub, grazing and developed area')
Known risk: where the risks are identified but ultimate value is not known. There are nine known risk factors: • Compulsory acquisition (BAU, low and high). • Cultural heritage (BAU, medium and high). • Environmental offset risks (BAU, low, high and very high). • Geotechnical findings (BAU, low and high). • Macroeconomic influence (BAU, increased uncertainty and heightened uncertainty). • Market activity (BAU, tight and excess capacity). • Outage restrictions (BAU, low and high). • Project complexity (BAU, partly complex and highly complex). • Weather delays (BAU, low and high).
Unknown risk: where the risk has not been identified but industry experience indicates these could occur: • Scope and technology (Class 5b, Class 5a and Class 4). • Productivity and labour cost (Class 5b, Class 5a and Class 4). • Plant procurement cost (Class 5b, Class 5a and Class 4). • Project overhead (Class 5b, Class 5a and Class 4).

[133] Rural Bank. Australian Farmland Values. 2022. At https://www.ruralbank.com.au/siteassets/_documents/publications/flv/afv-national-2022.pdf.

4.2 New South Wales

4.2.1 N1 - North West NSW

Summary	**Map**
The North-West New South Wales (NWNSW) REZ is located to the west of the existing QNI. While this zone has high-quality solar resources, the wind resource is estimated to be mostly inadequate for wind farm development. If generation significantly increases in NWNSW and New England REZs, increased connection capacity between the two REZs may be required. The sharing of resources across the network augmentation will allow for better transmission utilisation and reduction in transmission build. **Existing network capability** The existing 132 kV network is weak and would require significant network upgrades to accommodate VRE greater than the transmission network limit of approximately 170 MW.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Two new 500 kV circuits from Central-West Orana REZ to locality of Gilgandra to locality of Boggabri to locality of Moree. • A new single 500 kV circuit from Central-West Orana REZ to Wollar. • New 500/330 kV substations in locality of Boggabri and Moree. • A new 500 kV switching station in locality of Gilgandra. • A new 330 kV single-circuit from Sapphire to locality of Moree. • A new 330 kV circuit from Tamworth to locality of Boggabri. • Line shunt reactors at both ends of Central-West Orana REZ-locality of Gilgandra, locality of Gilgandra-locality of Boggabri, locality of Boggabri-locality of Moree 500 kV circuits. Pre-requisite: Central West Orana REZ Network Infrastructure project	1,660	5,770 Class 5b(±50%)	796	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW – Northern – Grazing Location (regional/distance factors): Remote	Known Risks: Project complexity: Partly complex Compulsory acquisition: High Others: BAU Unknown Risk: Class 5b

4.2.2 N2 - New England

Summary

New England REZ is located to the east of and along the existing QNI. The capacity of this REZ is supported by extensive Northern NSW – Central NSW corridor network options and it will be part of New England REZ Network Infrastructure Project.

This REZ has moderate to good wind and solar resources in close proximity to the 330 kV network. Interest in the area includes large scale solar and wind generation as well as pumped hydro generation.

The New England REZ was declared on 17 December 2021 under the *NSW Electricity Infrastructure Investment Act 2020* (NSW) with an intended 8,000 MW[134] of additional transmission network capacity to be constructed in the New England region of the state. The declaration identifies that EnergyCo NSW will be the infrastructure planner responsible for coordinating the development of the REZ[135]. REZ design and community engagement is currently progressing. The New England REZ Network Infrastructure Project includes proposed 500 kV and 330 kV transmission lines and substations between central and northern NSW to access increased renewable generation in northern NSW, as well as a 330 kV REZ extension. In the 2022 ISP, major augmentation of the CNSW-NNSW flow path was identified as an actionable New South Wales project (New England REZ Transmission Link) rather than an actionable ISP project. This project will progress under the Electricity Infrastructure Investment Act 2020 (NSW). EnergyCo has advised that it will be completed in two parts – Part 1 (CNSW-NNSW Option 1 and REZ N2 Option 1) by July 2032, and Part 2 (CNSW-NNSW Option 2) by January 2034[136].

Map

Existing network capability

The existing network capacity, following completion of the QNI Minor upgrade, is limited by transient and voltage stability on the circuits between Bulli Creek, Sapphire and Dumaresq. Thermal limits on the 330 kV circuits between Armidale, Tamworth, Muswellbrook and Liddell can also restrict flows on this network.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • New 330 kV Northern (Hub 10), Central South (Hub 1) and East (Hub 4) switching stations. • New 500 kV built and initially 330 kV operated DCST line from Central (Hub 5) to Central South (Hub1) with Quad Orange conductor. • New 500 kV built and initially 330 kV operated DCST line from Central (Hub 5) to Northern (Hub 10) with Quad Orange conductor. • New 330 kV DCST line between Central (Hub 5) and East (Hub 4) with Twin Olive conductor. Pre-requisite: CNSW-NNSW Option 1	2,400	1,055 Class 5b(±50%)	115	Medium: (6 years)
Option 2: • New South 330kV (Hub 2) switching station • New 330 kV DCST line from South (Hub 2) switching station to Central South (Hub 1) with Twin Olive conductor Pre-requisite: CNSW-NNSW Option 1 CNSW-NNSW Option 2	500	224 Class 5b(±50%)	30	Long: (8 years)

[134] See Government Gazette No 580 of Friday 15 December 2023, at https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2023_2023-580.pdf.

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

[136] See AEMO's Transmission Augmentation Information page, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Option 3: • New Hub 9 switching station. • Establish a new Lower Creek 330/132 kV substation with 1 x 330/132 kV 375 MVA transformer. • Rebuild part of Line 965 as 330 kV double-circuit from Armidale to Lower Creek. • Relocate existing 132 kV 200 MVA phase shift transformer on Line 965 from Armidale to Lower Creek. • New 330 kV double-circuit from Lower Creek to Hub 9. • Cut-in of Line 965 at new Lower Creek substation Pre-requisite: None	900	889 Class 5b(±50%)	121	Medium: (6 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Northern - Grazing Location (regional/distance factors): Remote	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: NSW - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Project complexity: Partly complex Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Tight Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Northern - Developed/NSW - Northern - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Project complexity: Partly complex Compulsory acquisition: High Others: BAU Unknown Risk: Class 5b

4.2.3 N3 - Central-West Orana

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>Central-West Orana REZ has been identified by the New South Wales Government as the state’s first pilot REZ. The Central-West Orana REZ is electrically close to the Sydney load centre and has moderate wind and solar resources.

The Central-West Orana REZ was declared on 5 November 2021 and amended in December 2023 under the NSW Electricity Infrastructure Investment Act 2020 (NSW)[137]. The Central-West Orana REZ has an intended 6,000 MW[138] of additional network capacity, with an initial stage of 4,500 MW to be delivered from 2027-28, to be constructed in the Central West New South Wales region of the state. The declaration identifies that EnergyCo NSW will be the infrastructure planner responsible for coordinating the development of the REZ.

The project to establish the Central-West Orana REZ is considered anticipated, with construction of Australia's first REZ commencing in mid-2025. EnergyCo have awarded 7.15 GW of generation and storage projects under its access rights scheme[139].

AEMO understands that Essential Energy and EnergyCo are exploring the concept of a Dubbo 'distribution REZ'. AEMO will continue to joint plan with both parties ahead of the release of the final 2025 Electricity Network Options Report.</td><td rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The project to establish the Central-West Orana REZ is considered anticipated. As such the existing network capability is assumed to be approximately 5,400 MW, incorporating the Central-West Orana REZ transmission link project (4,500 MW), as well as existing network capability (900 MW).</td></tr>
</table>

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Central West Orana REZ Network Infrastructure project: • New Merotherie 500/330 kV substation with 4 x 500/330/33 kV 1,500 MVA transformers. • New 330 kV Elong Elong switching stations. • New 500 kV Barigan Creek switching station. • 2 x 500 kV double-circuit lines from Barigan Creek to Merotherie with Quad Orange conductor. • 2 x 500 kV double-circuit lines and initially operated at 330 kV from Merotherie to Elong Elong with Quad Orange conductor. • 3 x 250 MVAr synchronous condensers at Elong Elong switching station. • 4 x 250 MVAr synchronous condensers at Merotherie substation. • Provision of switch bays for future generator connections (cost estimation is not required) • An additional 330 kV single-circuit line from Bayswater to Liddell. • An additional 330 kV single-circuit line from Mt Piper to Wallerawang. *possible expansion to Uungula/Burrendong is subject to a separate and future project authorisation process Pre-requisite: CNSW-SNW Option 1 when Central West Orana REZ exceeds 3 gigawatts (GW),	4,500	This project is considered to be anticipated and so is not included as an option here. The scope of the project is listed here for context so that the subsequent options can be understood. Option 1 includes expansions and augmentations to this project.		
Option 1: • Construct Merotherie-B 500/330kV substation with 3 x 500/330/33kV 1500 MVA transformers (at least 2 km away from	1,500	838 Class 5b(±50%)	13	Short: (5 years)

[137] See https://www.energyco.nsw.gov.au/cwo-rez.

[138] See Government Gazette No 580 of Friday 15 December 2023, at https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2023_2023-580.pdf.

[139] See https://www.energyco.nsw.gov.au/central-west-orana-access-scheme.

Merotherie substation – re-named as Merotherie-A). • Terminate one of the existing 500 kV DCST transmission lines between Merotherie – Barigan Creek at Merotherie-B and Wollar 500 kV substations respectively • Construct a DCST 500 kV transmission line between Merotherie-A and Merotherie-B 500 kV substations • Expand Elong Elong as 500/330 KV substation with 3 x 500/330/33kV 1500MVA Txs, • Operate Merotherie – Elong Elong transmission lines at 500kV • Terminate one of the 500 kV DCST transmission line from Merotherie - Elong-Elong at Merotherie-B Pre-requisite: Central West Orana REZ Network Infrastructure project				
Option 2: • New Tooraweenah 500/330 kV Hub with 3 x 500/330/33 kV 1,500 MVA transformers • New 500 kV DCST line from Tooraweenah to Merotherie with Quad Orange conductor • Augment Merotherie 500 kV substation Pre-requisite: N3 Option 1	2,100	TBC	TBC	Medium: (7 years)
Option 3: • New 330 kV Burrendong A and Burrendong B substations • New 500kV built and 330 kV operated double circuit lines from Elong Elong to Burrendong A Energy Hub • New 330 kV DCST line between Burrendong A and Burrendong B with Twin Olive conductor Pre-requisite: N3 Option 1	1,400	TBC	TBC	Medium: (7 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Northern - Grazing/NSW - Central - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Project complexity: Partly complex Others: BAU Unknown Risk: Class 5b
Option 2	AEMO is finalising these costs for the final *Electricity Network Options Report*	
Option 3	AEMO is finalising these costs for the final *Electricity Network Options Report*	

4.2.4 N4 - Broken Hill

Summary

Broken Hill REZ[140] has excellent solar resources. It is connected to the New South Wales grid via a 220 kV line from Buronga with an approximate length of 270 km.

This REZ is subject to a combined network limit (N4 + N5 + N13) represented by the SWNSW2 group constraint.

Map

Existing network capability

Due to the existing utility-scale solar and wind generation projects already operating in this REZ, there is no additional network capacity within this REZ.

Further development of new generation development in this REZ requires significant transmission network augmentation due to the distance of the REZ from the main transmission paths of the shared network.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • New 330 kV Western NSW switching station with 4x diameters, and cut in to both the Buronga - SA (PEC) lines • New 330 kV Broken Hill REZ Energy Hub 1 switching station with 2x diameters • New 139 km 500 kV constructed 330 kV energised DCST transmission line from Western NSW switching station to Broken Hill REZ Energy Hub 1 switching station Pre-requisite: Project EnergyConnect	800	1,117 Class 5b(±50%)	139	Long: (7 years)
Option 2: • 500 kV double-circuit HVDC line from Bannaby – Broken Hill (>850 km). • New HVDC converter stations at Bannaby and Broken Hill Pre-requisite: None	1,750	5,469 Class 5b(±50%)	932	Long: (9 years)
Option 3: • New 500 kV Moulamein switching station with 4x diameters, and cut in to the Dinawan - VIC (VNI West) lines • Expansion of the Western NSW site to a 500/330 kV substation with 4x diameters of 500 kV, and 2x 1,500 MVA 500/330 kV transformers • Expansion of the Broken Hill REZ Energy Hub 1 to a 500/330 kV substation with 1x additional diameter of 330 kV, 3x 1,500 MVA 500/330 kV transformers, and a 3x diameter 500 kV switchyard • New 261 km 500 kV DCST transmission line from Moulamein 500 kV switching station to Western NSW 500/330 kV substation • Energisation of 139 km line developed under Option 1 to 500 kV operation Pre-requisite: Project EnergyConnect VNI West REZ N4 Option 1	1,600	2,585 Class 5b(±50%)	261	Long: (9 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: NSW - Western -	Known Risks: BAU Unknown Risk: Class 5b

[140] AEMO notes that this REZ is not one of the first five REZs that have been declared by the New South Wales Government under its New South Wales Electricity Infrastructure Roadmap.

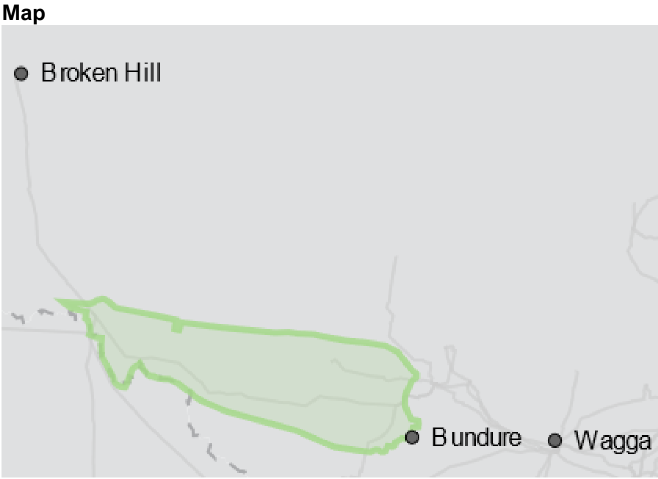
	Grazing Location (regional/distance factors): Remote	
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Western - Grazing Location (regional/distance factors): Remote	Known Risks: Project complexity: Highly complex Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 21+ / Applicable for HVDC converter station project Jurisdiction + Land use: NSW - Southern - Grazing/NSW - Western - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

4.2.5 N5 - South West NSW

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The South West NSW REZ has good solar resources and incorporates the Dinawan 330 kV substation that will be built as part of Project EnergyConnect. Further west, the 220 kV network links to North West Victoria and Broken Hill.

The South West NSW REZ was declared on 31 October 2022 under the NSW Electricity Infrastructure Investment Act 2020 (NSW) with an intended 2,500 MW[141] network capacity. EnergyCo have awarded 3.56 GW of generation and storage projects under its access scheme[142].

Network limits associated with the existing voltage stability limit for loss of the existing Darlington Point to Wagga Wagga 330 kV line are represented by the SWNSW1 secondary transmission limit.
As part of the IASR consultation, based on developer feedback further reviews of the wind quality data used in the AEMO ISP modelling is being undertaken for this REZ.

This REZ is subject to a combined network limit (N4 + N5 + N13) represented by the SWNSW2 group constraint.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>Due to the existing utility-scale solar projects already operating within this REZ, there is no additional capacity. Further development of new generation in this REZ requires network augmentation towards the greater Sydney load centre.

This limit is subject to review as part of the finalisation of the 2025 IASR. AEMO is continuing to joint plan with EnergyCo and Transgrid on this matter.

The capacity within this REZ and ability to transfer energy from the REZ to the main load centres in the greater Sydney area will be improved with the construction of Project EnergyConnect and HumeLink and VNI West projects.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td>Option 1[143]:
• Expand the existing Dinawan to 500/330kV substation with 3 x 500/330/33kV 1,500MVA transformers
• Expand the existing 500 kV Gugga substation to accommodate new Dinawan - Gugga 500 kV line
• Re-terminate the Dinawan - Wagga 330 kV DCST line (already built for 500 kV) at Dinawan 500 kV
• Re-terminate the Gugga - Wagga 330 kV DCST line (already built for 500 kV) at Gugga 500 kV
• Re-arrange the Dinawan - Wagga 330 kV DCST and Wagga - Gugga 330 kV DCST lines by disconnecting from Wagga and connecting together (bypassing Wagga) to make the 500 kV DCST transmission line between Dinawan and Gugga
• 500 kV line shunt reactors at Dinawan and Gugga on the Dinawan-Gugga 500 kV DCST transmission line
• Terminate Lower Tumut - Wagga 330 kV SCST line (line O51) at Gugga 330 kV
• Build 330 kV DCST transmission line between Gugga and Wagga, using the Line 051 easement

Pre-requisite: Project EnergyConnect and HumeLink</td><td>1,300</td><td>569
Class 5b(±50%)</td><td>30</td><td>Short: (3 years)</td></tr>
</table>

[141] See https://gazette.nsw.gov.au/gazette/2022/11/2022-515.pdf.

[142] See https://www.energyco.nsw.gov.au/south-west-rez-access-scheme.

[143] Option 1 is an alternative to the VNI West Project.

Option 3: Non-network option – virtual transmission line option with a 250 MW energy storage system in the SNW load centre and south of Wagga Wagga, with a SIPS scheme based on: • 250 MW of generation runback for generators connecting to Dinawan • 250 MW BESS in the Sydney-Newcastle-Wollongong load centre Pre-requisite: Project EnergyConnect HumeLink REZ N5 Option 1	250	Non-network augmentation	0	Short: (4 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 6 - 10 Jurisdiction + Land use: NSW - Southern - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 3	Non-network option not costed.	

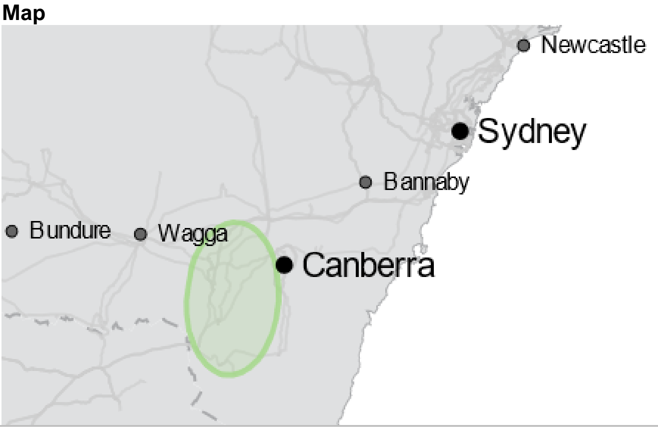
4.2.6 N6 - Wagga Wagga

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>Wagga Wagga REZ[140] extends to the west of Wagga Wagga and has moderate wind and solar resources.</td><td rowspan="3">Map

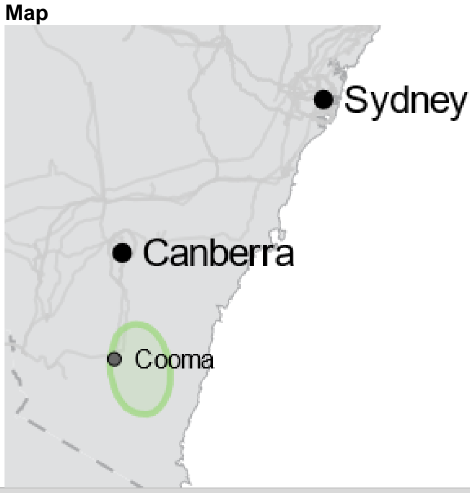
</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>The HumeLink project will enable the connection of more than 2,200 MW of generation in the Wagga and Tumut REZ areas. This REZ is subject to a combined network limit of 2,200 MW (N6 + N7). Further development of new generation in this REZ is associated with further network augmentations between SNSW and CNSW towards the greater Sydney load centre.</td></tr>
</table>

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Refer to SNSW-CNSW Option 3 and 4 subregional augmentations				

4.2.7 N7 – Tumut

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Tumut REZ has been identified due to the potential for additional pumped hydro generation in association with Snowy 2.0 and the anticipated HumeLink.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The HumeLink project will enable the connection of more than 2,200 MW of pumped hydro generation (Snowy 2.0) in the Tumut REZ area. This REZ is subject to a combined network limit of 2,200 MW (N6 + N7). Further development of new generation in this REZ is associated with further network augmentations between SNSW and CNSW towards the greater Sydney load centre.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to SNSW-CNSW Option 1 subregional augmentations</td></tr>
</table>

4.2.8 N8 - Cooma-Monaro

Summary	
The Cooma-Monaro REZ has been identified for its pumped hydro potential. This REZ has moderate to good quality wind resources.	**Map**
Existing network capability	
The existing 132 kV network connecting Cooma-Monaro REZ to Canberra, Williamsdale and Munyang can accommodate approximately 200 MW of additional generation.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • 132 kV single-circuit Williamsdale to Cooma-Monaro substation (located near generation interest) Pre-requisite: None	150	277 Class 5b(±50%)	74	Medium: (6 years)
Option 2: • 330 kV line Cooma-Williamdale-Stockdill • Two 330/132 kV transformers at Cooma Pre-requisite: None	500	660 Class 5b(±50%)	116	Short: (4 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: NSW - South East - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100-200 km/# of total Bays 6 - 10 Jurisdiction + Land use: NSW - South East - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

4.2.9 N9 - Hunter-Central Coast

Summary

The Hunter-Central Coast (HCC) REZ has been identified to assist industries to decarbonize and access renewable energy with a mix of solar, onshore and offshore wind energy projects.

The REZ has been declared with 1,000 MW of intended network capacity[144] and EnergyCo has been appointed the Infrastructure Planner enabled by the *Electricity Infrastructure Investment Act 2020*.

The capacity of the Hunter-Central Coast REZ is likely to increase over time with the retirement of coal-fired power stations, re-purposing of mining land and the growth of offshore wind.

This project was identified as an actionable NSW project in the 2024 ISP, and is now proceeding as an actionable New South Wales project rather than through the ISP framework.

Map

Existing network capability

EnergyCo have announced this REZ will supply both SNW and CNSW via Ausgrid's sub-transmission network (132 kV network), with the network normally open. EnergyCo have announced that this project will support up to 1,800 MW of generation and storage projects[145].

The upstream REZ transmission limit from Muswellbrook 330 kV substation is 400 MW, which assumes high southbound flows from NNSW to CNSW at peak demand.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: Component 1 • Minor augmentations of secondary systems to enable the connection of HCC REZ generation to the existing Ausgrid transmission and sub-transmission network Component 2 • New 132 kV Sandy Creek STSS • Singleton sub-transmission network is transferred to the Newcastle transmission network via Kurri STS (line 955 breakers are closed) Component 3 • New 132kV Antiene STSS • Two new 132kV lines from Antiene STSS to Kurri STS • A 7% series reactor installed at Rothbury Zone Substation • Opened breaker at 98N and 98R (Tomago to Beresfield) • Connections between Muswellbrook and Singleton networks are operated normally open Pre-requisite: None	1,000	TBC[146]	TBC	Short: (2 years)

Adjustment factors and risk

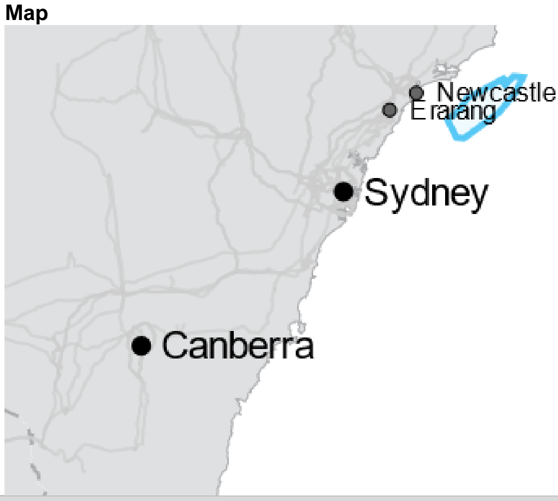
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	The Hunter-Central Coast REZ is being progressed by EnergyCo and Ausgrid. AEMO is joint planning with these bodies to incorporate a cost estimate for the final *Electricity Network Options Report*	

[144] See *Electricity Infrastructure Investment Act 2020* section 23(1)(e) at https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2022_2022-569.pdf.

[145] See https://www.energyco.nsw.gov.au/sites/default/files/2025-04/HCC%20REZ%20IPRR%20-%20Public%20Report%20-%20For%20CEO%20Approval%20-%2030%20April%202025.pdf.

[146] AEMO expects Ausgrid's cost estimate to be published in the final 2025 *Electricity Network Options Report.*

4.2.10 N10 - Hunter Coast

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Hunter Coast offshore REZ has been identified for the offshore wind resource potential in relatively shallow waters close to shore, with a connection point near to the Sydney load centre[147].</td><td colspan="4" rowspan="4">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>Newcastle has multiple 330 kV lines already connected and is situated near to the Sydney load centre. Network capacity is shared with local gas generation and coal generation output. The current network transmission limit is approximately 5,500 MW for new generation connections in the Newcastle and Eraring areas. This capacity could also be shared with any new generation connecting in the Hunter Central Coast REZ</td></tr>
<tr><td></td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to CNSW-SNW Option 1 subregional augmentations</td></tr>
</table>

[147] For more information, see Federal Government declaration of the REZ, at https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/hunter#:~:text=on%20Wind%20Turbines-,Area%20in%20the%20Pacific%20Ocean%20off%20the%20Hunter%20declared%20suitable,development%20on%2012%20July%202023.

4.2.11 N11 - Illawarra Coast

Summary

The Illawarra Coast offshore REZ has been identified for the offshore wind resource potential in relatively shallow waters close to shore, with a connection point near to the Sydney load centre[148].

Map

Existing network capability

Dapto has multiple 330 kV lines already connected and is situated near to the Sydney load centre. Network capacity is shared with local gas generation and hydro generation output. The current network transfer capacity is approximately 1,000 MW. This capacity could also be shared with any new generation connecting in the Illawarra REZ.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • 500 kV double-circuit line from Dapto – Marulan. • Two 500/330 kV 1,500 MVA transformers at Dapto. Pre-requisite: CNSW – SNW Option 3 or CNSW-SNW Option 4	2,000	899 Class 5b(±50%)	75	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Compulsory acquisition: High Outage restrictions: High Others: BAU Unknown Risk: Class 5b

148 For more information, see Federal Government declaration of the REZ, at https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/illawarra.

4.2.12 N12 – Illawarra

Summary	Map
The Illawarra REZ was formally declared by the Minister for Energy in NSW on 27 February 2023[149]. Community consultation has been initiated by EnergyCo, following an earlier Registration of Interest that highlighted potential for wind (onshore and offshore), solar, energy storage, pumped hydro, hydrogen production, and green steel manufacturing. The REZ has been declared with 1,000 MW of intended network capacity and EnergyCo has been appointed the Infrastructure Planner enabled by the *Electricity Infrastructure Investment Act 2020*.	
Existing network capability	
Dapto has multiple 330 kV lines already connected and is situated near to the Sydney load centre. Network capacity is shared with local gas generation and hydro generation output. The intended network capacity for this REZ is approximately 1,000 MW	

Augmentation options

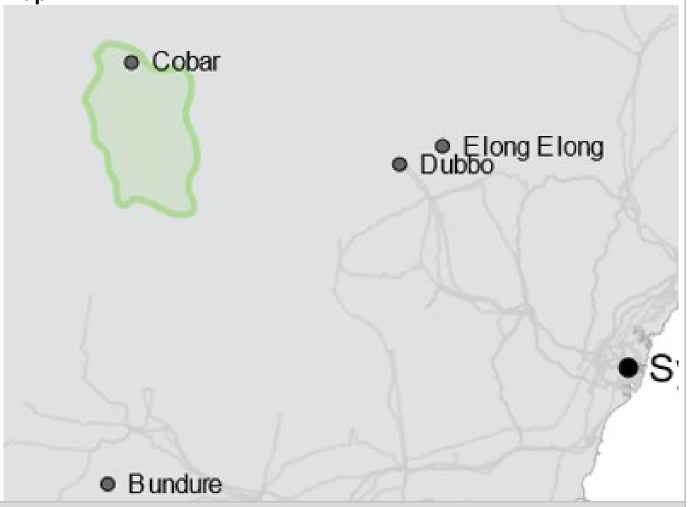
Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • 500 kV double-circuit line from Dapto – Marulan. • Two 500/330 kV 1,500 MVA transformers at Dapto. Pre-requisite: CNSW – SNW Option 3 or CNSW-SNW Option 4	2,000	899 Class 5b(±50%)	75	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Developed Location (regional/distance factors): Regional/Urban	Known Risks: Project complexity: Partly complex Compulsory acquisition: High Outage restrictions: High Others: BAU Unknown Risk: Class 5b

[149] See https://www.energyco.nsw.gov.au/ilw-rez.

4.2.13 N13 - South Cobar

Summary	Map
South Cobar REZ[140] is a new candidate REZ proposed for the 2026 ISP with high quality wind and solar resources. It is connected to the NSW grid via the existing 132 kV line from Cobar.	
Existing network capability	
South Cobar REZ has a limited initial capacity of approximately 100 MW due to the single 132 kV connection to the NSW grid. Further development of new generation in this REZ requires significant transmission network augmentation due to the distance of the REZ from the main transmission paths of the shared network. This REZ is subject to a combined network limit (N4 + N5 + N13) represented by the SWNSW2 group constraint.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • New South Cobar 330 kV switching station with 2x diameters • Expansion of Dinawan 330 kV switchyard by 2x 330 kV diameters • New 357 km 330 kV DCST transmission line from Dinawan to South Cobar 330 kV switching station • 50 MVAr shunt reactor on each new circuit at South Cobar and Dinawan[150], including a switching station halfway between South Cobar and Dinawan for reactive line compensation. Pre-requisite: Project EnergyConnect	1,000	2,050 Class 5b(±50%)	363	Long: (7 years)
Option 2: • New South Cobar 500/330 kV substation with 3x 500 kV diameters, 3x 1500 MVA transformers, 3x 330 kV diameters • Expansion of Dinawan 500 kV switchyard by 2x 500 kV diameters • New 357 km 500 kV DCST transmission line from Dinawan to South Cobar 500/330 kV substation • 100 MVAr shunt reactor on each new circuit at South Cobar and Dinawan[150], including a switching station halfway between South Cobar and Dinawan for reactive line compensation. Pre-requisite: VNI West	2,400	3,186 Class 5b(±50%)	363	Long: (7 years)
Option 3: • New South Cobar 500/330 kV substation with 3x 500 kV diameters, 3x 1500 MVA transformers, 3x 330 kV diameters • New 500 kV switching station on VNI West line with 4x 500 kV diameters • New 355 km 500 kV DCST transmission line from new switching station on VNI West line to South Cobar 500/330 kV substation • 100 MVAr shunt reactor on each new circuit at South Cobar and VNI Switching station[150], including a switching station halfway between South Cobar and Dinawan for reactive line compensation. Pre-requisite: VNI West	2,400	3,240 Class 5b(±50%)	363	Long: (7 years)
Option 4: • New Cobar 500/330 kV Hub with 3 x 500/330/33 kV 1,500 MVA transformers	2,400	3,189 Class 5b(±50%)	363	Medium: (6 years)

[150] AEMO (National Planner) will undertake joint planning with Transgrid to refine the required reactive line compensation in the final 2025 *Electricity Network Options Report.*

• New 500 kV DCST line from Cobar to Elong Elong with Quad Orange conductor • Install 150 MVAr, 500 kV reactors at both ends of the new Cobar - Elong Elong 500 kV circuits[150], including a switching station halfway between South Cobar and Dinawan for reactive line compensation., including a switching station halfway between South Cobar and Elong Elong for reactive line compensation. • Augment Elong Elong 500 kV substation to accommodate new lines Pre-requisite: N3 Option 1				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Grazing/NSW - Southern - Grazing Location (regional/distance factors): Remote/Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: NSW - Central - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

4.2.15 SWNSW1 - Secondary Transmission Limit - South West NSW

Summary

Network limits associated with the existing voltage stability limit for loss of the existing Darlington Point to Wagga 330 kV line are represented by the SWNSW1 secondary transmission limit. This limit applies to the existing generation in the South West NSW region.

Existing network capability

The SWNSW1 secondary limit is determined by the output of the existing generation in South West NSW when line 63 voltage stability constraints are binding.

This puts a total limit on existing generation in the region at 1200 MW. This consists of existing South West generation (~1030 MW), Broken Hill Solar, Broken hill BESS and Silverton Wind Farm (~50 MW), with an assumed uplift for a network support agreement in place (~120 MW). This has been updated to incorporate the N4 Broken Hill REZ contribution.

AEMO and Transgrid continue to joint plan on the revising of this limit for after Project EnergyConnect is fully commissioned, as it could be expected to increase up to 1600 MW at this point. This limit will be revised for the final 2025 IASR.

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • New 90 km 330 kV single circuit transmission line between Transgrid's Darlington Point 330 kV Substation and Dinawan 330 kV Switching Station: • Expansion of Darlington Point 330 kV yard by one breaker and a half diameter with 2 x CBs; • Expansion of Dinawan 330 kV yard by one breaker and a half diameter with 2 x CBs. Pre-requisite: Project EnergyConnect HumeLink	Removes secondary transmission limit	167[151] Class 5a(±30%)	90	Medium: (6 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Cost estimate provided by Transgrid	

[151] This is the $2023 cost estimate for the Darlington point – Dinawan 330 kV line option as presented in *the Improving Stability in Southwest New South Wales* project PACR. AEMO (National Planner) will undertake joint planning with Transgrid to incorporate an updated cost estimate in the final 2025 *Electricity Network Options Report*.

4.2.16 SWNSW2 - Group Constraint - for the Broken Hill, South West and South Cobar REZ

<table>
<tr><th colspan="6">Summary</th></tr>
<tr><td colspan="2">The Group constraint SWNSW2 represents the generation-built limit applied to N4 Broken Hill, N5 South West and a potential N13 South Cobar southern connection. This constraint is necessary as newly proposed options for N4 and N13 have them connecting to the network at or near Dinawan creating a bottleneck on the Dinawan – Gugaa/Wagga circuit. This group constraint is split into two stages before and after the VNI West project.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><td colspan="2">Existing network capability</td></tr>
<tr><td colspan="2">Prior to VNI West, the Dinawan-Wagga 330 kV circuit will limit the SWNSW2 group to TBC giving the following group constraint N4+N5 – SNSW-CSA < TBC.

Post VNI West, the Dinawan – Gugaa circuit is operated at 500 kV raising the limit to TBD giving the following group constraint N4+N5+N13 – SNSW-CSA – 0.8 SNSW-WNV < TBC.

In both versions of the SWNSW2 constraint the existing generation which contributes to the SWNSW1 group constraint is not included.

AEMO, Transgrid and EnergyCo are continuing to joint plan to formulate this constraint.</td></tr>
<tr><th colspan="6">Augmentation options</th></tr>
<tr><td colspan="2">Description</td><td>Additional network capacity (MW)</td><td>Expected cost ($ million)</td><td>New easement length (km)</td><td>Lead time</td></tr>
<tr><td colspan="6">No augmentation options proposed</td></tr>
<tr><th colspan="6">Adjustment factors and risk</th></tr>
<tr><td>Option</td><td colspan="2">Adjustment factors applied</td><td colspan="3">Known and unknown risks applied</td></tr>
<tr><td colspan="6">No augmentation options proposed</td></tr>
</table>

4.3 Queensland

4.3.1 Q1 - Far North QLD

Summary	
The Far North Queensland (FNQ) REZ is at the most northerly section of Powerlink's network. It has good wind and moderate solar resources and has existing hydroelectric power stations. One option is proposed that increases network capacity and allows for upgrades based on where generation develops.	**Map** 
Existing network capability	
The current total REZ transmission limit for existing and new VRE before any network upgrade in Far North Queensland is approximately 750 MW for peak demand, summer typical and winter reference conditions.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Establish a new 275 kV substation in the Lakeland area • Build a double-circuit 275 kV line from Walkamin to the new substation near Lakeland • Build a new 275 kV Chalumbin to Walkamin single-circuit line • Rebuild the double-circuit Chalumbin to Ross 275 kV line at a higher capacity (possibly timed with asset replacement) • Build additional Chalumbin to Ross 275 kV double-circuit tower but switch as a single-circuit line (energise second line as generation develops) Pre-requisite: None	1,290	4,023 Class 5b(±50%)	723	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 11 - 15 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b

4.3.2 Q2 - North Qld Clean Energy Hub

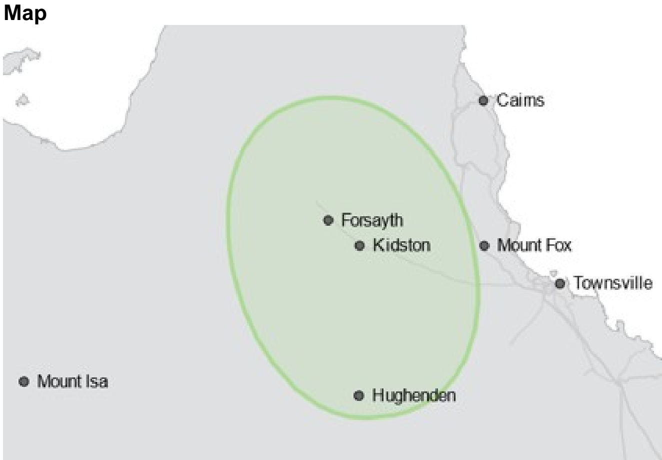
Summary

The Clean Energy Hub REZ is at the north-western section of Powerlink's network, and has excellent wind and solar resources.

The Queensland Government has announced that it will deliver the approximately 840 km CopperString 2032 project. CopperString 2032 will connect the North-West Minerals Province of Queensland to the NEM near Townsville[152]. The project scope includes 500 kV transmission capacity between Townsville and Hughenden to unlock the renewable energy potential of the region.

AEMO considers the CopperString 2032 project as an anticipated project after outcomes from joint planning with Powerlink and the Queensland Government. CopperString 2032 incorporates the 500 kV section of the Queensland Energy and Jobs Plan (QEJP) SuperGrid Stage 4.

Map



Existing network capability

The project to establish CopperString 2032 is considered anticipated. As such, the existing network capability is assumed to be approximately 2,200 MW, incorporating the CopperString 2032 project (1,500 MW) as well as existing network capability (700 MW)[153] for peak demand, summer typical and winter reference conditions. For the 2024 ISP, only the 500 kV section of CopperString 2032 was modelled.

The existing network at the North-West Mineral Province is islanded from the NEM. The NEM only extends as far west as Julia Creek and is mainly energised at 66 kV in that area. The existing network for this REZ was designed to support North-West Queensland load, rather than building for future generation projects. The REZ can potentially support much more generation with more transmission infrastructure.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option Q2 CopperString 2032: • Establish a new 500 kV substation south of Townsville (NQ 500 kV substation) • Install 2 x 500/275 kV 1,500 MVA transformers at NQ 500 kV substation • Establish a new 275 kV substation • Cut-in the Strathmore to Ross 275 kV double-circuit line to the NQ substation • Establish a new 500 kV substation at Hughenden with associated switchgear, bays, and required 500/330 kV transformers • Establish a new 500 kV substation (mid-point between NQ 500 kV and Hughenden substations) with associated switchgear and bays • A new 500 kV transmission line from south of Townsville to Hughenden • A new 330 kV transmission line from Hughenden to Cloncurry • A new 220 kV transmission line from Cloncurry to Mount Isa • Up to six new substation sites • Associated static and dynamic reactive plant • (Only the 500 kV transmission line from south of Townsville to Hughenden to be modelled for the purpose of the 2024 Integrated System Plan and 2025 Electricity Network Options Report) Pre-requisite: None	1,500 nominal 2,300 if CQ-NQ Option 2 is selected.	This project is considered to be anticipated and so is not included as an option here. The scope of the project is listed here for context only.		

[152] See Section 2.3.1 of Powerlink's Transmission Annual Planning Report, at https://www.powerlink.com.au/sites/default/files/2024-04/Transmission%20Annual%20Planning%20Report%20-%202023%20-%20Full%20Document.pdf.

[153] The existing network capacity assumes the 275 kV line from Guybal Munjan to Kidston being delivered as part of the committed Kidston pumped hydro energy storage project.

Option 1: • Establish a 275 kV yard at Kidston substation near Forsayth • Build a 275 kV double-circuit line from Kidston to Guybal Munjan substation (energise only a single line until generation in the REZ develops, then energise the second line) Pre-requisite: None	500	1,058 Class 5b(±50%)	190	Long: (10 years)
Option 2: • Establish a 275 kV yard at Kidston substation near Forsayth • Build a 275 kV double-circuit line from Kidston to Guybal Munjan substation Pre-requisite: Q2 Option 1	1,000	1,100 Class 5b(±50%)	190	Long: (10 years)

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: Environmental offset risks: Low Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: Environmental offset risks: Low Others: BAU Unknown Risk: Class 5b

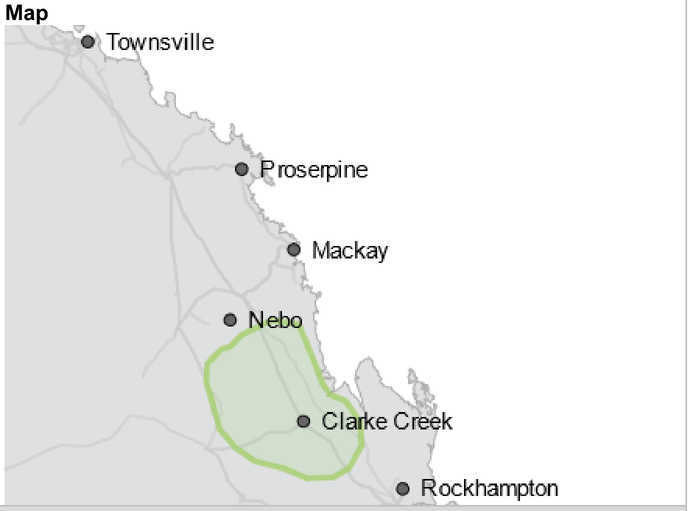
4.3.3 Q3 - Northern Qld

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>The North Queensland REZ encompasses Townsville and the surrounding area. It has good quality solar and wind resources and is situated close to the high-capacity 275 kV network. There are already a number of existing large-scale solar generation projects operational within this REZ.</td><td rowspan="3">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>Existing network capacity can allow for up to approximately 2,420 MW of new generator connections for peak demand and summer typical conditions and 2,650 MW for winter reference conditions, shared between Q1, Q2 and Q3 as given by group constraint NQ1.</td></tr>
</table>

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Refer to NQ1 group constraint augmentations				

4.3.4 Q4 - Isaac

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Isaac REZ has good wind and solar resources and has a number of large-scale solar generation projects already in operation. There are numerous potential pumped hydro locations to the north east and south east of Nebo. This REZ has a good diversity of resources – wind, solar and storage. Locating storage in this zone could maximise transmission utilisation towards Brisbane.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The Isaac REZ forms part of the CQ transmission backbone between Nebo and Broadsound. Due to the existing high voltage infrastructure, there are no augmentation options specifically for this REZ. The associated augmentations are the CQ1 group constraint and CQ – NQ flow path augmentations that facilitate power from Northern Queensland and Q4 to be transmitted south to the load centres.

The network has the ability to support to a total of 1,700 MW of generation in summer peak and summer typical conditions and 2,070 MW in winter reference conditions as given by group constraint CQ1.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to CQ1 group constraint augmentations:</td></tr>
</table>

4.3.5 Q5 – Barcaldine

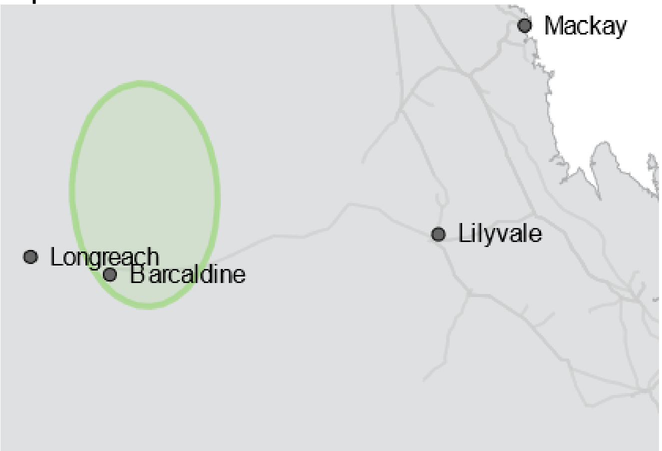
Summary

This REZ has excellent solar resources and moderate wind resources but is located a long way from the Queensland transmission backbone. Barcaldine REZ has not been identified as having significant potential pumped hydro capability.

Existing network capability

The current total REZ transmission limit for existing and new VRE before any network upgrade in Barcaldine is approximately 85 MW for peak demand, summer typical and winter reference conditions.

Map



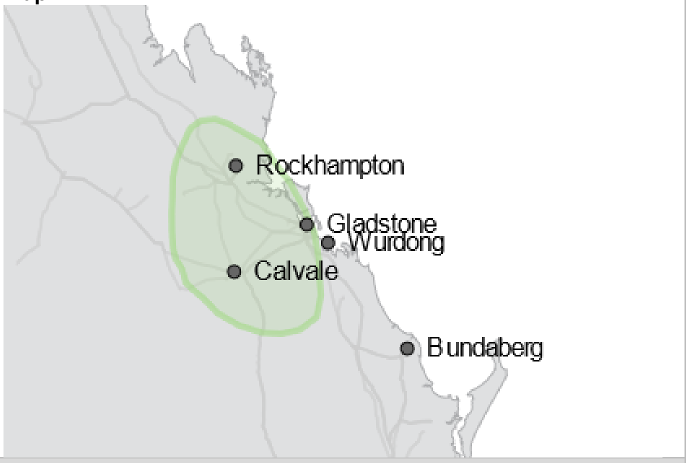
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Establish a 275 kV substation in the Barcaldine region • Build a 340 km 275 kV double-circuit line from Lilyvale to Barcaldine (energise only a single line until generation in the REZ develops) Pre-requisite: None	500	1,598 Class 5b(±50%)	340	Long: (7 years)
Option 2: • Energise the second circuit on the line established in Option 1 • Additional substation bays and reactors if required Pre-requisite: Q5 Option 1	850	0	0	Medium: (6 years)

Adjustment factors and risk

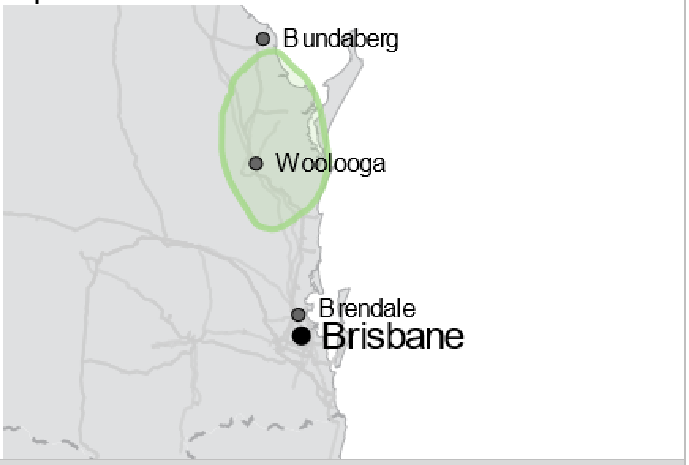
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Scrub Location (regional/distance factors): Remote Location wind loading zones: Cyclone region	Known Risks: Compulsory acquisition: Low Environmental offset risks: Low Others: BAU Unknown Risk: Class 5b
Option 2	None	None

4.3.6 Q6 – Fitzroy

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Fitzroy REZ is in Central Queensland and covers a strong part of the network where Gladstone and Callide generators are connected. This REZ has good solar and wind resources. It is the focal point for power transfer from Central and Northern Queensland to the load centre in Southern Queensland.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>This Fitzroy network internal capability is limited by the thermal capacity of the Calvale–Wurdong, Bouldercombe–Calliope River, Bouldercombe–Raglan, Larcom Creek–Calliope River or Calliope River–Wurdong 275 kV circuits. Network capability to export electricity to southern Queensland is shared between VRE generation within Fitzroy REZ and other generation within northern and central Queensland.

Due to the existing high voltage infrastructure, there are no augmentation options specifically for this REZ. The associated augmentations are the Central Queensland to Gladstone Grid flow path augmentations.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to CQ-GG flow path augmentations:</td></tr>
</table>

4.3.7 Q7 - Wide Bay

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Wide Bay area has moderate solar resources and already has a number of large solar PV generators operational within the REZ. There is difficulty acquiring easements in this residential area, however Powerlink do have a double width easement most of the way from Woolooga to Palmwoods and to South Pine, so double-circuits would be built in-situ next to the existing circuits, then the single-circuit would be de-energised. This may help reduce those challenges around obtaining easements as well as obtaining outages of critical circuits, should the generation interest exceed the current network capacity.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The existing network facilitates power transfer from Central Queensland to the load centre in Brisbane. This is a 275 kV transmission backbone and currently supports up to approximately 1,400 MW of power flow from CQ into Brisbane during summer peak, summer typical and winter reference conditions. This means the maximum VRE output in the REZ is highly dependent on CQ – SQ flow.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to SQ1 group constraint augmentations:</td></tr>
</table>

4.3.8 Q8 - Darling Downs

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Darling Downs REZ extends from the border of NSW around Dumaresq, up to Columboola within the Surat region of Queensland, and has good solar and wind resources. A number of large solar and wind projects are already connected within the zone.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The Darling Downs REZ has high network capacity and is near QNI and Brisbane. Furthermore, the ultimate retirement of generation within this REZ will allow for increased VRE connections.

The existing network facilitates power transfer from south west Queensland to the load centre in Brisbane. This transmission can support up to approximately 5,300 MW of generation into Brisbane during summer peak, summer typical and winter reference conditions. However this capability is significantly reduced depending on the output of generation in the Western Downs area, generation in the Darling Downs area, generation in the Southern Downs area, the flow of power from NSW, and the flow of power from central Queensland. To capture these sensitivities the augmentations are associated with the SWQLD1 transmission limit constraint that facilitates power flow to load centres in south east Queensland.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to SWQLD1 transmission limit constraint augmentations:</td></tr>
</table>

4.3.9 Q9 – Banana

Summary

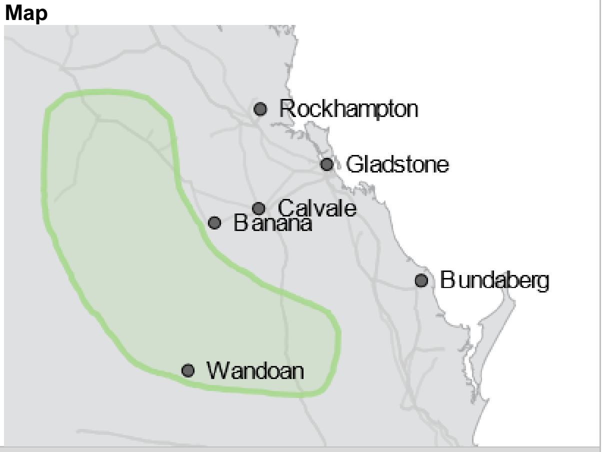
The Banana REZ is located approximately 200 km south-west of Gladstone and lies north of the CQ – SQ flow path. It has moderate wind and excellent solar resources. There are currently no generators and very little high voltage network in this area. The first two options are proposals that transport the power to the Gladstone region. Substation locations both within the Banana REZ and towards connection points near Gladstone will be based on where generation and load develop.

AEMO understands from the Queensland Government and from Powerlink that transmission augmentation projects for the Banana REZ are likely to be delivered as a dedicated asset of some kind. This may need to be treated similar to a generation connection asset in the ISP model, rather than like a network augmentation option.

Existing network capability

There is currently very little high voltage network in the area. There is some 132 kV network on the edge of the REZ, supporting the townships of Moura and Biloela. There is very little spare capacity within the network.

Map



Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Establish a new 500 kV substation within the Banana REZ • 200 km double-circuit 500 kV line from the Banana REZ to CQ substation associated with SQ-CQ Option 5 or SQ-CQ Option 6 • Additional 500/275 kV 1,500 MVA transformer at the CQ substation • Switchgear at CQ substation Pre-requisite: SQ-CQ Option 5 or SQ-CQ Option 6	3,000	1,519 Class 5b(±50%)	220	Long: (7 years)
Option 2: • Establish a new 275 kV substation within the Banana REZ • 100 km high temperature conductor (HTC) double-circuit 275 kV line from Banana REZ to Calvale substation • Associated switchgear • Limit extension special protection scheme (similar to a virtual transmission line) – cost of non-network service agreement excluded Pre-requisite: CQ-GG Option 1 or CQ-GG Option 2	1,800	839 Class 5b(±50%)	144	Medium: (6 years)
Option 3: • Establish a new 275 kV substation within the Banana REZ • 195 km double-circuit 275 kV line from Banana REZ to Wandoan South • Switchgear at Wandoan South Pre-requisite: None	1,000	521 Class 5b(±50%)	102	Medium: (6 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

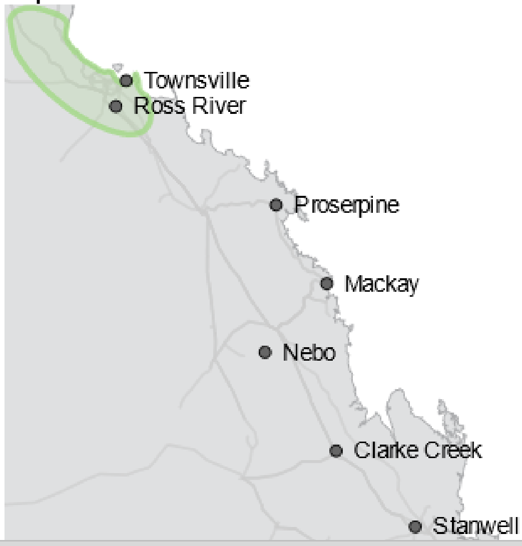
4.3.10 Q10 – Collinsville

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td rowspan="3">The Collinsville REZ has good wind and solar resources and has a number of large-scale solar generation projects already in operation. There are numerous potential pumped hydro locations to the north east and south east of Nebo. This REZ has a good diversity of resources – wind, solar and storage. Locating storage in this zone could maximise transmission utilisation towards Brisbane.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>The Collinsville REZ forms part of the NQ transmission backbone between Strathmore and Nebo. Due to the existing high voltage infrastructure, there are no augmentations options specifically for this REZ. The associated augmentations are the CQ – NQ flow path augmentations that facilitate power from Northern Queensland to be transmitted south to the load centres.

From NQ to CQ, the maximum transfer capability is 1,440 MW at peak demand and summer typical levels and 1,910 MW at winter reference periods, assuming Powerlink upgrades the limiting 8 km of line into Ross from Strathmore 275 kV.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to CQ-NQ flow path augmentations</td></tr>
</table>

4.3.11 NQ1 - Group Constraint

Summary	Map
Upgrade options associated with the Group Constraint NQ1 may be built when total generation in Q1 + Q2 + Q3 (North Queensland) exceed 2,420 MW for peak demand and summer typical conditions, and 2,650 MW for winter reference conditions. This augmentation facilitates transmission from North Queensland to load centres in Central and Southern Queensland.	
Existing network capability	
The current network was designed to facilitate the transmission of power from Central Queensland to supply load in Northern Queensland. The network has the ability to support up to 2,420 MW of generation across the three REZs in North Queensland for peak demand and summer typical conditions, and 2,650 MW for winter reference conditions.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new 275 kV double-circuit line from Ross to Strathmore to Nebo, initially switching one side only Pre-requisite: Assume BAU line refit of 275 kV and 132 kV network between Bouldercombe-Nebo-Strathmore-Ross	680	1,736 Class 5b(±50%)	335	Long: (10 years)
Option 2: • 500 kV substation works at Mulgrave (near Townsville 500 kV established as part of CopperString 2032 project) • A new 500 kV substation at locality of northern part of CQ (around 27 km south of Broadsound) • A new 500 kV substation at locality of southern part of NQ (around 80 km south of Nebo) • A new 500 kV double-circuit steel tower (DCST) line from CQ (west of Gladstone) to northern CQ substation • A new 500 kV DCST line from northern CQ to southern NQ substations • A new 500 kV DCST line from southern NQ substation to Mulgrave substation • 2 x 500/275 kV 1,500 MVA transformers at northern CQ and southern NQ substations • Cut-in 275 kV circuits between Stanwell and Broadsound to northern CQ substation and between Broadsound and Nebo to southern NQ substation • Special protection scheme for transfer limit increase (similar to virtual transmission line) with the cost of this Network Service Agreement (NSA) excluded Pre-requisite: SQ-CQ Option 3 (QEJP) and Q2 CopperString 2032 Project	3,000	4,670 Class 5b(±50%)	623	Long: (10 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - North - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b

Option 2	Delivery timetable: Optimum Project network element size: Above 200 km/# of total Bays 16 - 20 Jurisdiction + Land use: QLD - Central - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b

4.3.12 CQ1 – Group Constraint

Summary

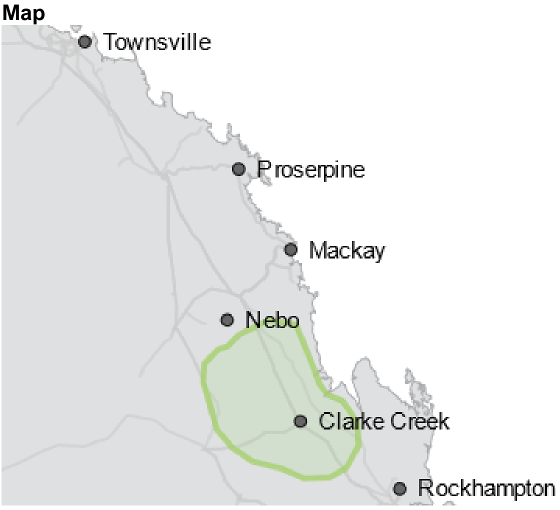
Upgrade options associated with the Group Constraint CQ1 may be built to improve the generation capacity in Northern Queensland and Q4. These augmentations will facilitate transmission of this generation to load centres in the south.

Existing network capability

The current network was designed to facilitate the transmission of power from Central Queensland to support the load in Northern Queensland. Thus, its capacity was designed around North Queensland load, rather than building for future generation projects.

The network has the ability to support up to 1,700 MW of generation during summer peak and summer typical conditions and 2,070 MW during winter reference conditions

Map



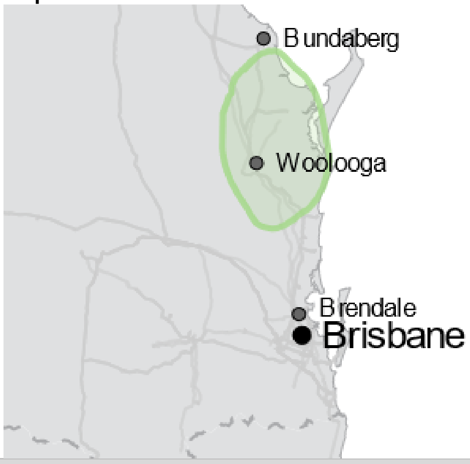
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • String and energise the second Broadsound to Stanwell 275 kV Pre-requisite: None	600	203 Class 5b(±50%)	0	Short: (4 years)
Option 2: • Rebuild Broadsound to Bouldercombe 275 kV line (820) as a part of end-of-life refurbishment Pre-requisite: None	1,600	517 Class 5b(±50%)	146	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - Central - Scrub Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: BAU Unknown Risk: Class 5b

4.3.13 SQ1 - Group Constraint

Summary	Map
Upgrade options associated with the Group Constraint SQ1 may be built to improve the generation capacity in Central Queensland and Q7. These augmentations will facilitate transmission of this generation to load centres in the locality of Brisbane. The Queensland SuperGrid project could affect future augmentations and capacity limits associated to this group constraint, and as such will also be included as part of this constraint in the ISP modelling process.	
Existing network capability	
This is a 275 kV transmission backbone and currently supports up to approximately 1,400 MW of power flow from CQ into Brisbane during summer peak, summer typical and winter reference conditions. This means the maximum VRE output in the REZ is highly dependent on CQ-SQ flow.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Rebuild Woolooga to Palmwood to South Pine 275 kV single-circuit line as a high-capacity double-circuit line • 100 MVAr reactor for voltage control Pre-requisite: None	1,100	997 Class 5b(±50%)	168	Long: (7 years)
Option 2: • Rebuild Woolooga to South Pine 275 kV single-circuit line as a high-capacity double-circuit line • 100 MVAr reactor for voltage control Pre-requisite: None	1,100	885 Class 5b(±50%)	158	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: Compulsory acquisition: Low Geotechnical findings: Low Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional Location wind loading zones: Cyclone region	Known Risks: Compulsory acquisition: Low Geotechnical findings: Low Outage restrictions: High Others: BAU Unknown Risk: Class 5b

4.3.14 SWQLD1 - Transmission Limit Constraint

Summary

Upgrade options associated with the transmission limit constraint SWQLD1 (the Darling Downs) may be required to increase the generation capacity in southwest Queensland. These augmentations will facilitate transmission of this generation to load centres in the locality of Brisbane. In the 2024 ISP, the optimal development path requires expansion in the Darling Downs in 2034-35. Either Option 1 or Option 2 could be developed for this REZ. Which of Option 1 or Option 2 is chosen as the future ISP option would be informed by joint planning between AEMO and Powerlink over which option would produce the largest net benefit.

Existing network capability

The existing network facilitates power transfer from south west Queensland to the load centre in Brisbane. This transmission can support up to approximately 5,300 MW of generation into Brisbane during summer peak, summer typical and winter reference conditions. This capability depends on the generation in the Western Downs area, the generation in the Darling Downs area, the generation in the Southern Downs area, the flow of power from New South Wales and the flow of power from central Queensland.

Map

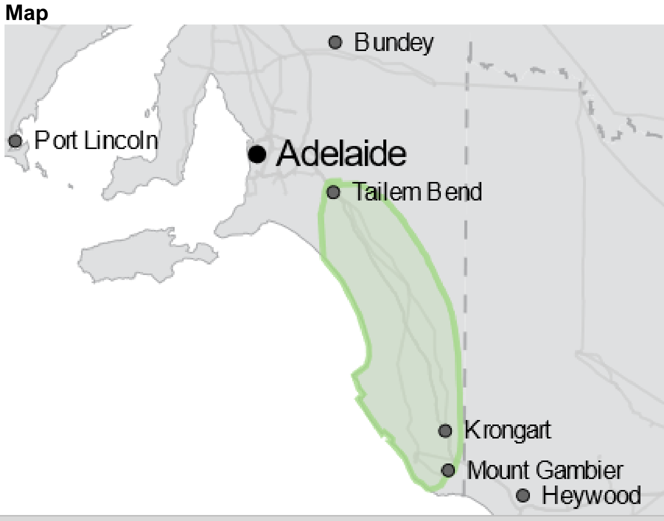
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Replace existing 330/275 kV 1,300 MVA transformer at Middle Ridge with 330/275 kV 1,500 MVA transformer Pre-requisite: None	150	26 Class 5b(±50%)	0	Short: (2 years)
Option 2: • Implement a limit extension special protection scheme – run-back of generation in south-west Queensland with 300 MW battery energy storage system (BESS) response in south-east Queensland (similar to a virtual transmission line) Pre-requisite: Can be implemented with or without SWQLD1 Option 1	330	7 Class 5b(±50%)	0	Short: (2 years)
Option 3: • Establish a second 330 kV substation to the east of the existing Tummaville substation • Install 8 x 330/330 kV 300 MVA phase-shifting transformers (PST) between the two 330 kV substations Pre-requisite: Can be implemented with or without SWQLD1 Option 1	400	479 Class 5b(±50%)	0	Long: (7 years)
Option 4: •Pre-requisite is 500 kV double-circuit line from New England REZ North Hub (Hub 10) to Halys • New 2 x 500/275 kV 1,500 MVA transformers at Western Downs with associated switchgear and bays • Cut-in 500 kV double-circuit single tower lines from Halys to NNSW and associated switchgear and bays Pre-requisite: NNSW–SQ Option 2a and SQ-CQ Option 5 or SQ-CQ Option 6	1,500	259 Class 5b(±50%)	0	Long: (7 years)
Option 5: • Establish a REZ Hub substation 70 km from Wandoan South • Double-circuit 275 kV line between Wandoan South and REZ Hub (twin Sulphur) – 70 km • Double-circuit 275 kV line between REZ Hub and Auburn River (twin HTC) – 100 km • Second double-circuit HTC 275 kV line will be built between REZ Hub and Auburn River depending on variable renewable energy (VRE) development Pre-requisite: SQ-CQ Option 2	0 (SWQLD1 Option 5 does not impact the SWQLD1 limit and only allows more generation to connect at this local part of the network)	915 Class 5b(±50%)	156	Medium: (6 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Delivery timetable: Optimum Project network element size: # of total Bays 1 - 5 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Compulsory acquisition: Low Environmental offset risks: Low Geotechnical findings: Low Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: # of total Bays 1 - 5 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: Below 5 km/# of total Bays 11 - 15 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 4	Delivery timetable: Optimum Project network element size: Below 5 km/# of total Bays 1 - 5 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 5	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 6 - 10 Jurisdiction + Land use: QLD - South - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

4.4 South Australia

4.4.1 S1 - South East SA

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The South East South Australia REZ lies on the major 275 kV route of the South Australia – Victoria Heywood interconnector. The REZ has moderate to good quality wind resources, as evidenced by the high proportion of wind generation (over 300 MW) in or near the South East border with Victoria.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The existing network capacity of this REZ was modelled as part of South East South Australia – Central South Australia (SESA-CSA) sub-regional maximum transfer capability of 750 MW. There are no augmentation options specifically for this REZ. The associated augmentations are the WNV-SESA and SESA-CSA flow path augmentations.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to NWV-SESA and SESA-CSA sub-regional augmentations</td></tr>
</table>

4.4.2 S2 – Riverland

Summary	
The Riverland REZ is on the South Australian side of the proposed Project EnergyConnect route. It has good quality solar resources.	**Map**
Existing network capability	
There is minimal existing renewable generation in the zone. Prior to Project EnergyConnect, approximately 130 MW can be connected in this REZ for all three operating conditions (peak demand, summer typical and winter reference). Once Project EnergyConnect is commissioned, the REZ transmission limit increases by approximately 800 MW. Development options for this REZ assess additional network capacity post Project EnergyConnect.	

Augmentation options

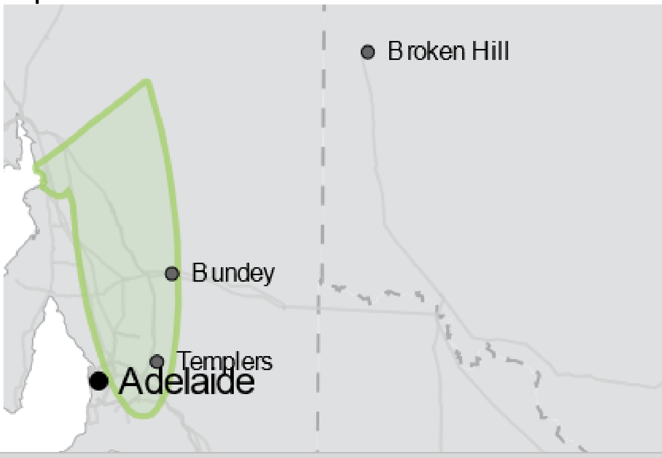
Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Co-ordinate new connections through turn in of Bundey – Buronga 330 kV No. 1 and No. 2 lines into a new substation at Riverland. • 2x 275/132 kV Tx at new Riverland substation Pre-requisite: None	700	149 Class 5b(±50%)	0	Short: (4 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Long Project network element size: Below 5 km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

4.4.3 S3 - Mid-North SA

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td rowspan="3">The Mid-North South Australia REZ has moderate quality wind and solar resources. There are several major wind farms in service, in this REZ, totaling more than 1,700 MW of installed or committed capacity. Four 275 kV parallel circuits provide the bulk transmission along the corridor from Davenport to near Adelaide (Para) which traverse this REZ. This transmission corridor forms the backbone for exporting power from REZs north and west of this REZ in South Australia towards the Adelaide load centre.

ElectraNet completed preparatory activities for the Mid-North South Australia REZ expansion in 2023 and it was identified as an actionable project in the 2024 ISP.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr></tr>
<tr></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The capability of this zone to accommodate new generation is subject to the MN1 mid-north group constraint.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to MN1 group constraint augmentations</td></tr>
</table>

4.4.4 S4 - Yorke Peninsula

Summary

The Yorke Peninsula REZ has good quality wind resources. A single 132 kV line extends from Hummocks to Wattle Point (towards the end of Yorke Peninsula).

Existing network capability

The existing 132 kV network has 100 MW of additional network capacity for all three operating conditions (peak demand, summer typical and winter reference). Transmission augmentation is required to connect any significant additional generation in this REZ. The capability of this zone to accommodate new generation is also subject to the MN1 mid-north group constraint.

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • String first circuit of a 275 kV double-circuit line from Blythe West into new Yorke Peninsula substation. Pre-requisite: MN1 Option 1	450	629 Class 5b(±50%)	148	Medium: (6 years)
Option 2: • String second circuit of a 275 kV double-circuit line from Blythe West into new Yorke Peninsula substation. • 2x 275/132 kV Tx at new Yorke Peninsula substation • Cut in of Templers West into Bundey-Para 275 kV line. Pre-requisite: MN1 Option 1, S4 Option 1	450	193 Class 5b(±50%)	148	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - York and North - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - York and North - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

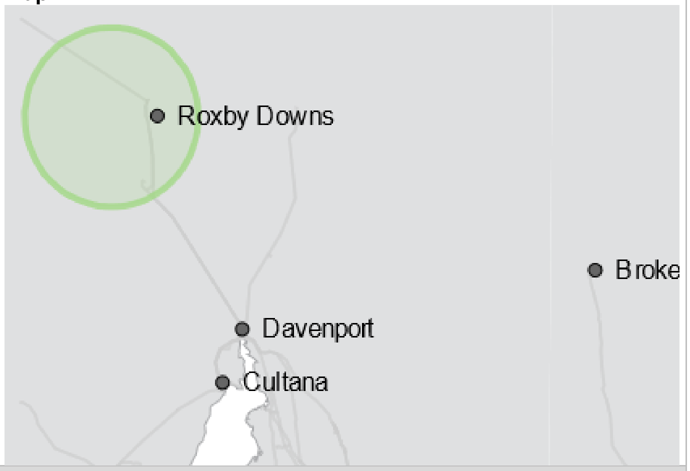
4.4.5 S5 - Northern SA

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Northern SA REZ has good solar and moderate wind resources. This REZ area is updated to include the Whyalla West proposed release area[154] by the South Australian government for development of renewable energy projects pursuant to the Hydrogen and Renewable Energy Act 2023.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The capability of this zone to accommodate new generation is subject to the MN1 mid-north and NSA1 northern group constraint.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to NSA1 group constraint augmentations</td></tr>
</table>

[154] At https://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/1068893/Whyalla-West-information-pack.pdf.

4.4.6 S6 - Roxby Downs

Summary	**Map**
The Roxby Downs REZ is located a few hundred kilometres north-west of Davenport. It has excellent solar resource quality. The only significant load in the area is the Olympic Dam and Carrapateena mines. This REZ is currently connected with a 132 kV line that provides supply to small loads, and two privately owned 275 kV lines from Davenport that provide supply to large mines in the area.	
Existing network capability	
The existing network capacity of this REZ is 500 MW, although the capability of this zone to accommodate new generation is subject to the MN1 mid-north group constraint.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Build 275 kV double-circuit line from Davenport to new Roxby Downs substation. • 2x 275/132 kV Tx at new Roxby Downs substation Pre-requisite: None	950	1,326 Class 5b(±50%)	254	Short: (5 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Long Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: SA - Eyre Peninsula - Scrub Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

4.4.7 S7 - Eastern Eyre Peninsula

Summary	**Map**
The Eastern Eyre Peninsula REZ has moderate to good quality wind resources. The Eyre Peninsula Link was completed in February 2023. It replaced the existing Cultana–Yadnarie–Port Lincoln 132 kV single-circuit line with a new double-circuit 132 kV line. The section between Cultana to Yadnarie is built to operate at 275 kV, however, it is initially energised at 132 kV. ElectraNet published an Eyre Peninsula Upgrade Project Assessment Draft Report[155] in March 2025 to identify options to further increase network capacity in this corridor and meet potential load developments on the Eyre Peninsula region. **Existing network capability** The existing network capacity of this REZ is 300 MW (subject to the capacity of the 275/132 kV transformers at Cultana). The capability of this zone to accommodate new generation is subject to the MN1 mid-north and NSA1 northern group constraint.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • A new Yadnarie North substation with two new 275/132 kV transformers. • Operate the Cultana-Yadnarie 132 kV double-circuit line (built as part of the Eyre Peninsula Link RIT-T[156]) at 275 kV. • Reconnect 132 kV connections to 275 kV at both Yadnarie North and Cultana. Pre-requisite: None	300	179[157] Class 4 (+50/-30%)	0	Short: (4 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimates provided by ElectraNet	

155 See https://electranet.com.au/wp-content/uploads/2025/03/Public_Eyre-Peninsula-Upgrade_PADR.pdf.

156 See https://electranet.com.au/wp-content/uploads/2025/03/FINAL-Eyre-Peninsula-Electricity-Supply-Options-PACR-17-Oct-2018.pdf.

157 This is the $2025 cost estimate for Option 1 of the Eyre Peninsula Upgrade project as presented in the PADR.

4.4.8 S8 - Western Eyre Peninsula

Summary	Map
The Western Eyre Peninsula REZ shares the same electrical network as the Eastern Eyre Peninsula. It has good solar and moderate wind resources. There are no generators currently connected or committed within this REZ.	
Existing network capability	
There is no additional network capacity within this REZ. The capability of this zone to accommodate new generation is subject to the MN1 mid-north and NSA1 northern group constraint.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • 275 kV double-circuit line from Cultana East to a new Elliston substation. • 2x 275/132 kV Tx at new Elliston substation Pre-requisite: None	950	1,431 Class 5b(±50%)	285	Long: (7 years)
Option 2: • 275 kV single-circuit line from Yadnarie to a new Elliston substation. • 2x 275/132 kV Tx at new Elliston substation Pre-requisite: S7 Option 1	500	664 Class 5b(±50%)	160	Long: (7 years)
Option 3: • New Elliston substation. • Single-circuit 275 kV line from Cultana/Corraberra Hill/Cultana East to Elliston. • Single-circuit 275 kV line from Yadnarie to Elliston. • 2x 275/132 kV Tx at new Elliston substation Pre-requisite: S7 Option 1	1,000	1,671 Class 5b(±50%)	445	Long: (7 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Long Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - Eyre Peninsula - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Long Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - Eyre Peninsula - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Long Project network element size: Above 200 km/# of total Bays 6 - 10 Jurisdiction + Land use: SA - Eyre Peninsula - Grazing Location (regional/distance factors): Remote	Known Risks: BAU Unknown Risk: Class 5b

4.4.9 MN1 - Group Constraint

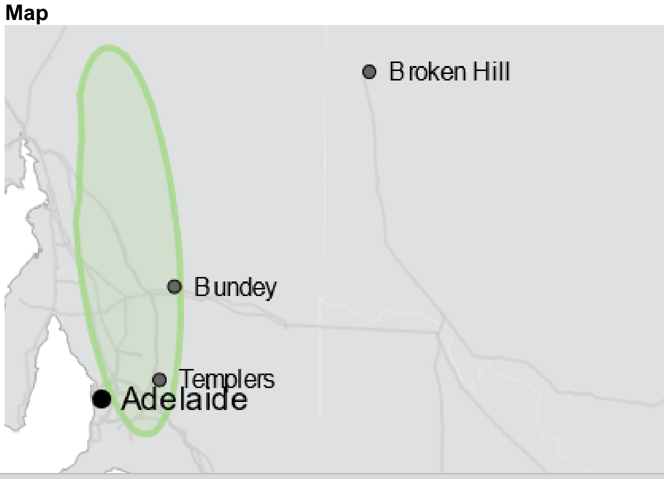
Summary

The Group Constraint MN1 represents the generation build limit applied to S3, S4, S5, S6, S7, S8, and S9 REZs. This constraint is necessary because these REZs all must export any additional power generation south towards Adelaide primarily along the existing four 275 kV parallel circuits from Davenport to near Adelaide (Para). This corridor of the network forms a bottleneck for these REZs.
The application of this group constraint will be removed for the *Green Energy Exports* scenario.

Existing network capability

The individual REZs which form this group constraint each have their own individual existing network capabilities. The collective generation from S3 and S4 and the flow through CSA-NSA cannot exceed 1,630 MW without additional network augmentation between Davenport and Adelaide.

Map



Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: (ISP Candidate Option) • Build a 275 kV double-circuit line between Bundey and Para. • 2x new line-connected reactors at Bundey • 2x new line-connected reactors at Para • Disconnect existing Waterloo-Templers 132 kV line at each end. • Build a 132 kV single-circuit line from Templers West to Templers. • 1 x 160 MVA, 275/132 kV transformer at Templers West Pre-requisite: None	1,200	820[158] Class 5(±50%)	TBC	Short: (4 years)
Option 2: • Build a 275 kV double-circuit line from Bundey to Globe Derby (twin conductor Olive) • 2x new 275 kV line-connected reactors at Bundey • New 275 kV GIS substation at Globe Derby, number of diameters between 2 and 5. • 2x new 275 kV line-connected reactors at Globe Derby • Connect Globe Derby to existing metropolitan 275 kV network. • Disconnect existing Waterloo-Templers 132 kV line at each end. • Build a 132 kV single-circuit line from Templers West to Templers. • 1 x 160 MVA, 275/132 kV transformer at Templers West Pre-requisite: None	1,150	1,037 Class 5b(±50%)	139	Short: (4 years)
Option 3: • Build a 330 kV double-circuit line from Bundey to Globe Derby (triple conductor Mango) • 2x330 kV line-connected reactors at Bundey • New 330 kV GIS substation at Globe Derby, incl. 3x700 MVA • • 330/275 kV transformers, at least 4 x 330 kV exits and 8 x 275 kV exits • 2x new 330 kV line-connected reactors at Globe Derby • Connect Globe Derby to existing metropolitan 275 kV network. • Disconnect existing Waterloo-Templers 132 kV line at each end. • Build a 132 kV single-circuit line from Templers West to Templers. • 1 x 160 MVA, 275/132 kV transformer at Templers West Pre-requisite: None	1,150	1,210 Class 5b(±50%)	139	Short: (4 years)

[158] This value has been provided by ElectraNet. AEMO (National Planner) and ElectraNet will joint plan on the inclusion of an updated value in the final 2025 *Electricity Network Options Report.*

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Estimate provided by ElectraNet. This value includes an unknown risk component.	
Option 2	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 11 - 15 Jurisdiction + Land use: SA - Adelaide and Fleurieu - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b

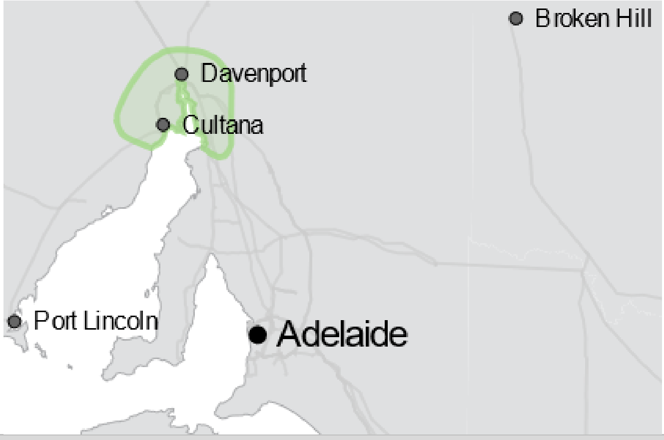
4.4.10 NSA1 - Group Constraint

Summary

The Group Constraint NSA1 represents the generation build limit applied to S5, S8, and S9 REZs. This constraint is necessary because these REZs all must export power through the Davenport – Cultana 275 kV circuits. This corridor of the network forms a bottleneck for these REZs.

The application of this group constraint will be removed for the Green Energy Exports scenario.

Map



Existing network capability

The individual REZs which form this group constraint each have their own individual existing network capabilities. The collective generation from Northern SA (new entrant VRE, S5, S7 and S8, less the CSA Export, Electrolyser load, and NSA Demand) cannot exceed 585 MW without additional network augmentation between Davenport and Cultana.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Build a 275 kV double-circuit line from Davenport-Carriewerloo-Cultana. Pre-requisite: None	900	484[159] Class 4 (+50/-30%)	122	Short: (4 years)

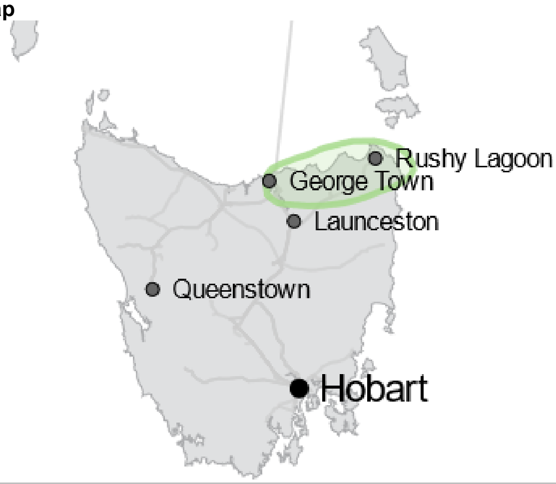
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimates provided by ElectraNet	

[159] This is the $2025 cost estimate for Option 4 of the Eyre Peninsula Upgrade project as presented in the PADR.

4.5 Tasmania

4.5.1 T1 - North East Tasmania

Summary	**Map**
This REZ has a good quality wind resources and moderate solar resources. North East Tasmania is remote from the actionable Project Marinus and therefore upgrades are less influenced by its status.	
Existing network capability	
Currently there is no capacity on the 110 kV network from Hadspen to Derby. There is approximately 400 MW of VRE resource capacity available within the vicinity of George Town. The capability of this zone to accommodate new generation is subject to the NET1 northeast Tasmania group constraint.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Build new substation at Long Reach, cutting into transmission lines from George Town to Sheffield and Hadspen substations • Build new Far North East wind collector station • 220 kV double-circuit line between new Long Reach substation and new substation in far north-east Tasmania. Pre-requisite: None	800	715 Class 5b(±50%)	100	Long: (8 years)
Option 2: • Second 220 kV double-circuit line between the new substations in Long Reach and far north-east Tasmania, strung one side only. Pre-requisite: T1 Option 1	800	565 Class 5b(±50%)	100	Long: (8 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: TAS - Northern - Grazing/TAS - Northern - Developed Location (regional/distance factors): Regional/Urban	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: TAS - Northern - Developed Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

4.5.2 T2 - North West Tasmania

Summary

This REZ has excellent quality wind resources and good pumped hydro resources. The North West Tasmania augmentation options are highly dependent on Project Marinus, with some REZ network capacity increase already included in the proposed Project Marinus AC North West Transmission Plan development.

In May 2024, the Tasmanian Government released a proposed REZ Area for consultation for North West Tasmania[160], and AEMO will include outcomes of this consultation in subsequent studies.

Map

Existing network capability

The current total REZ transmission limit for existing (112 MW Granville Harbour Wind Farm) and new VRE before any network upgrade in North West Tasmania is approximately 277 MW for peak demand and summer typical conditions and 112 MW for winter reference condition. This REZ is affected by transient stability constraints for VRE connection at Farrell 220 kV substation. Future REZ generators are assumed to have a runback scheme in place to reduce generation output post contingency to within network capacity for lines currently covered by the Network Control System Protection Scheme (NCSPS), but not for new transmission lines.

Augmentation options

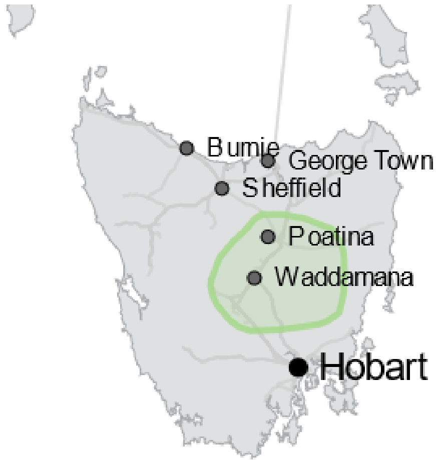
Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Build a new double-circuit Burnie-Hampshire Hills 220 kV line • Build a new Hampshire Hills wind collector station. Pre-requisite: TAS-SEV Option 1	800	217 Class 5b(±50%)	30	Short: (4 years)
Option 2: • Build new “Farrell 2” wind collector station on west coast Tasmania (nearby existing Farrell substation) • Build new double-circuit Farrell2-Hampshire Hills 220 kV line. • Build second Hampshire Hills-Burnie-Heybridge 220 kV line. Pre-requisite: TAS-SEV Option 2, T2 Option 1	800	732 Class 5b(±50%)	95	Long: (8 years)
Option 3: • Build double-circuit West Montagu-Hampshire 220 kV line. • Build a second 220 kV double-circuit line from Hampshire Hills to Burnie to Heybridge. Pre-requisite: TAS-SEV Option 2, T2 Option 1	800	895 Class 5b(±50%)	132	Long: (8 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: TAS - North West - Developed Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: TAS - North West - Developed/TAS - North West - Scrub Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 3	Delivery timetable: Tight Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: TAS - North West - Grazing/TAS - North West - Developed Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b

[160] See https://www.renewableenergyzones.tas.gov.au/.

4.5.3 T3 - Central Highlands

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>This REZ has excellent quality wind resources, and has good pumped hydro resources. It is located close to major load centres at Hobart. Timing of the Tasmania Central Highlands REZ augmentation options are influenced by the timing of Project Marinus augmentations. Waddamana to Palmerston transfer capability upgrade was an actionable project in the 2024 ISP. The updated options have been provided by TasNetworks through joint planning and are being modelled as part of the RIT-T.</td><td rowspan="3">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>The current total REZ transmission limit for existing (144 MW Cattle Hill Wind Farm) and new VRE before any network upgrade (but considering minor operational improvements) in the Central Highlands is approximately 527 MW for peak demand and summer typical conditions and 668 MW for winter reference condition[161]. VRE development opportunities are anticipated around the Waddamana substation.

Note that a runback scheme is not considered for any new transmission lines.</td></tr>
</table>

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: (ISP Candidate Option) • Build a Palmerston-Waddamana 220 kV double-circuit line. Pre-requisite: TAS-SEV Option 1	690	201 Class 5a[162] (±30%)	60	Medium: (6 years)
Option 1A: • Convert Waddamana-Palmerston 110 kV line to 220 kV operation (line did previously operate at 220 kV) • Re-string with HTLS conductor • Install 220/110 kV transformer at Waddamana Substation Pre-requisite: TAS-SEV Option 1	725	77 Class 5b(±50%)	44	Short: (4 years)
Option 2: • Re-build of Palmerston-Hadspen- George Town 220 kV transmission line Pre-requisite: T3 Option 1 or 1A	690	571 Class 5b(±50%)	84	Long: (8 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Cost estimate provided by TasNetworks	
Option 1A	Delivery timetable: Tight Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: TAS - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Tight Project network element size: 5 to 100 km Jurisdiction + Land use: TAS - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

[161] AEMO is currently joint planning with TasNetworks to refine the existing network capability for T3 REZ to reflect potential increase in capacity following minor network upgrades. Revised existing and resultant additional network options and capacities will be published in the final IASR and *Electricity Network Options Report*.

[162] This $2023 cost estimate has been provided by TasNetworks. AEMO (National Planner) will undertake joint planning with TasNetworks to incorporate an updated cost estimate in the final 2025 *Electricity Network Options Report*.

4.5.4 T4 - North Tasmania Coast

Summary

The North Tasmania Coast REZ has been identified for the offshore wind resource potential in relatively shallow waters close to shore, with a connection point close to existing 220 kV networks.

Existing network capability

North West Tasmania Coast REZ connects to the 220 kV network within the North West REZ or North East REZ. Two potential connection points for this offshore REZ are in the vicinity of Burnie or George Town, and the REZ transmission network limit for each connection point is considered differently.

For a connection to the 220 kV network in the vicinity of Burnie, the total REZ transmission network limit for existing and new VRE is included as part of the North West REZ limit of approximately 277 MW for peak demand and summer typical conditions and 112 MW for winter reference condition.

For a connection to the 220 kV network in the vicinity of George Town, the total REZ transmission network limit for existing and new VRE is included as part of the North East Tasmania NET1 group constraint with a combined network limit of 1,600 MW for offshore wind and onshore VRE from T1.

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: •Build a second Burnie-Heybridge -Sheffield 220 kV double-circuit line Pre-requisite: TAS-VIC Option 2	1,360	340 Class 5b(±50%)	51	Long: (8 years)
Option 2: • Build a second George Town-Sheffield 220 kV double-circuit line. • Build 2 x power flow controllers on the 2 x 220 kV double-circuit line between George Town-Hadspen. • Build a new substation co-located to George Town Pre-requisite: TAS-VIC Option 2	900	395 Class 5b(±50%)	66	Long: (8 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 6 - 10 Jurisdiction + Land use: TAS - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b
Option 2	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: TAS - Northern - Grazing Location (regional/distance factors): Regional	Known Risks: BAU Unknown Risk: Class 5b

4.7 Victoria

Onshore candidate REZs in Victoria are displayed consistent with the indicative draft REZs published for consultation in May 2025 in the Victorian Government's Draft 2025 *Victorian Transmission Plan*.

AEMO notes that these new draft REZ options are yet to be finalised with VicGrid as it progresses the final *Victorian Transmission Plan*. AEMO continues to joint plan with Victorian jurisdictional bodies for these priority REZs in the near term, as well as considering the longer ISP time horizon.

4.7.1 V1 – North West

Summary	**Map**
The North West REZ (in previous ISPs this was part of V2 - Murray River REZ) has good solar and wind resource quality. Despite being remote, this REZ has attracted significant investment in solar generation. Voltage stability and thermal limits currently restrict the output of generators within this REZ. The actionable VNI West project will upgrade transfer capability between Victoria and New South Wales via Bulgana, and significantly increase the ability for renewable generation to connect in this zone. As noted in the 2024 *Victorian Annual Planning Report*, voltage oscillation constraints affecting this area are expected to reduce following delivery of the Victorian Government's RDP system strengthening projects.	
Existing network capability	
The current REZ transmission limits for existing and new VRE before any network upgrade in North West is approximately 440 MW for peak demand and summer typical conditions and 640 MW for winter reference condition. There is no additional capacity to connect new generation.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Kerang/New Kerang – Bendigo. Pre-requisite: VNI West Western VIC reinforcement WRL	200	380 Class 5[163] (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	126	Long: (9 years)
Option 2: • Rebuild existing single circuit to high-capacity 220 kV double circuit between Red Cliffs-Wemen-Kerang. Pre-requisite: VNI West Western VIC reinforcement WRL V1 Option 1	530	690 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	248	Long: (9 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 2	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

163 These are unadjusted cost estimates provided by VicGrid. AEMO understands these to be classified as Class 5 estimates under the AACE classification system.

4.7.2 V2 – Central Highlands

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>The Central Highlands REZ (in previous ISPs this was part of V3 – Western Victoria [V3 West] REZ) has good wind resource quality. The existing and committed renewable generation within this REZ exceeds 630 MW, all of which is from wind generation.

The Western Renewables Link uprated (WRL) is an anticipated project, and increases the ability for renewable generation to connect in this zone. VNI West further increases the network capability in this REZ.

REZ augmentation options shown take into account the WRL (uprate) scope as part of the VNI West RIT-T utilising 500 kV from Sydenham to Bulgana.</td><td rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The current REZ transmission limits for existing and new VRE before any network upgrade in Central Highlands is approximately 600 MW for peak demand and summer typical conditions and 800 MW for winter reference condition.</td></tr>
</table>

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Option 1: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Ballarat (BATS) – Moorabool (MLTS) #1.	400	240 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	64	Short: (2 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

4.7.3 V3 – Wimmera Grampians

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Wimmera Grampians REZ (in previous ISPs this was part of V3 – Western Victoria [V3 East] REZ) has good wind resource quality. The existing and committed renewable generation within this REZ exceeds 760 MW, all of which is from wind generation.

The Western Renewables Link uprated (WRL) is an anticipated project, and significantly increases the ability for renewable generation to connect in this zone. VNI West further increases the network capability in this REZ.

REZ augmentation options shown take into account the WRL (uprate) scope as part of the VNI West RIT-T utilizing 500 kV from Sydenham to Bulgana.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The current REZ transmission limits for existing and new VRE before any network upgrade in Wimmera Grampians and Wimmera Southern Mallee is approximately 780 MW for peak demand and summer typical conditions and 980 MW for winter reference condition.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td>Option 1:
• Rebuild existing single circuit to high-capacity 220 kV double circuit from Murra Warra to Horsham to Ballarat.

Pre-requisite: VNI West
Western VIC reinforcement
WRL</td><td>600</td><td>680
Class 5
(+100%/-50%)
[VicGrid value subject to adjustment and risk section notes below]</td><td>225</td><td>Long (9 years)</td></tr>
<tr><th colspan="5">Adjustment factors and risk</th></tr>
<tr><th>Option</th><th colspan="2">Adjustment factors applied</th><th colspan="2">Known and unknown risks applied</th></tr>
<tr><td>Option 1</td><td colspan="4">Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.</td></tr>
</table>

4.7.4 V4 – Wimmera Southern Mallee

Summary	Map
The Wimmera Southern Mallee REZ (in previous ISPs this was part of V3 – Western Victoria [V3 East] REZ) has good wind resource quality. The existing and committed renewable generation within this REZ exceeds 450 MW of wind and 118 MW of solar generation. REZ augmentation options shown take into account the WRL (uprate) scope as part of the VNI West RIT-T utilising 500 kV from Sydenham to Bulgana.	
Existing network capability	
The current REZ transmission limits for existing and new VRE before any network upgrade in Wimmera Southern Mallee is to be confirmed.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Murra Warra to Horsham to Ballarat Pre-requisite: VNI West Western VIC reinforcement WRL	600	680 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	225	Long (9 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

4.7.5 V5 – South West

Summary	
The South West REZ (in previous ISPs this was part of V4 – South West Victoria REZ) has moderate wind resource quality in close proximity to the 500 kV and 220 kV networks in the area. The total committed and in-service wind generation in the area exceeds 3 GW.	**Map**
Existing network capability	
The current REZ transmission limits for existing and new VRE before any network upgrade in South West Victoria are limited by voltage stability, and this REZ was modelled with the SWV1 group constraint. This limit is approximately 1,850 MW prior to commissioning of the Victorian Government's RDP: Mortlake turn in project.	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Refer to SWV1 group constraint augmentations				

4.7.6 V6 – Gippsland Onshore

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Gippsland Onshore REZ (in previous ISPs this was part of V5 – Gippsland REZ) has moderate wind resource quality, in proximity to the 500 kV networks.</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>The transmission limit of the Gippsland REZ is modelled with the SEV-MEL flow path limit.

Due to the high capacity of the network in this REZ (with four 500 kV and six 220 kV lines from Latrobe Valley to Melbourne designed to transport energy from major Victorian brown coal power stations), significant generation can be accommodated. However, limitations exist at key points of 500/220 kV transformation.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to SEV-MEL flow path options</td></tr>
</table>

4.7.7 V7 – Central North

Summary

The Central North REZ (in previous ISPs this was part of V6 – Central North Victoria REZ) has moderate solar and wind resource quality. In addition to the currently in service and committed solar farms, there are enquires for over 1 GW of additional solar.

Existing network capability

The current REZ transmission limits for existing and new VRE before any network upgrade in Central North Victoria are approximately 650 MW for peak demand and summer typical conditions and 1,300 MW for the winter reference condition.

Map

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Shepparton to Dederang via Glenrowan. Pre-requisite: None	250	470 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	155	Long: (8 years)
Option 2: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Shepparton – Near Bendigo Pre-requisite: None	500	370 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	120	Long: (8 years)

Adjustment factors and risk

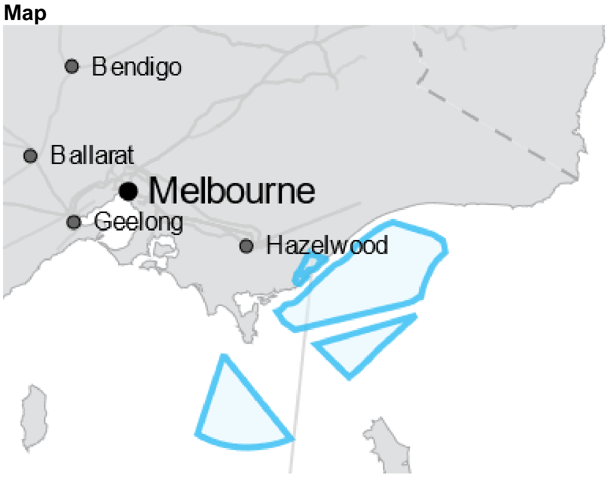
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 2	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

4.7.8 V8 – Gippsland Shoreline

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td>The Gippsland Shoreline REZ (in previous ISPs this was part of V7 – Gippsland Coast REZ) has been identified for offshore wind resource potential in relatively shallow waters, with a connection point close to existing 500 kV networks at Loy Yang/Hazelwood. There is currently significant interest in this area, but proposed projects have not developed sufficiently to be considered anticipated.

The Victorian Government has announced that VicGrid will provide a coordinated transmission connection point for offshore wind near the Gippsland Shoreline. New transmission lines will also be developed where needed to link the common connection points with the existing energy grid.

AEMO understands that transmission augmentation projects for Gippsland Shoreline REZ are likely to be delivered as a dedicated asset of some kind.

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter[164].</td><td colspan="4" rowspan="3">Map

</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>Gippsland shoreline REZ requires connection to the 500 kV network.</td></tr>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td colspan="5">Refer to SEVIC1 group constraint augmentations</td></tr>
</table>

[164] See https://www.energy.vic.gov.au/renewable-energy/vicgrid/offshore-wind-transmission.

4.7.9 V9 – Southern Ocean

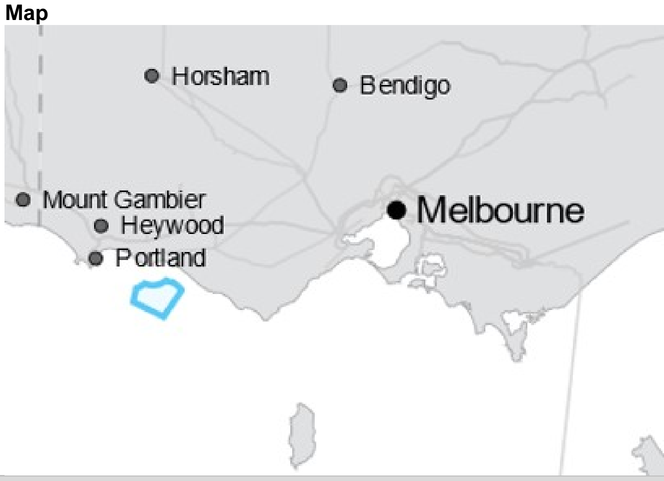
Summary

The Southern Ocean REZ has been identified for offshore wind resource potential in relatively shallow waters, with a connection point close to existing 500 kV networks at Alcoa Portland (APD)/Heywood.

The Victorian Government has announced that VicGrid will provide a coordinated transmission connection point near Portland.

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.

Map



Existing network capability

The network capacity available for V9 is the same as V5 South West Victoria. REZ augmentation options are common to those shown for V5 and V9, and this REZ has been modelled as part of the SWV1 group constraint.

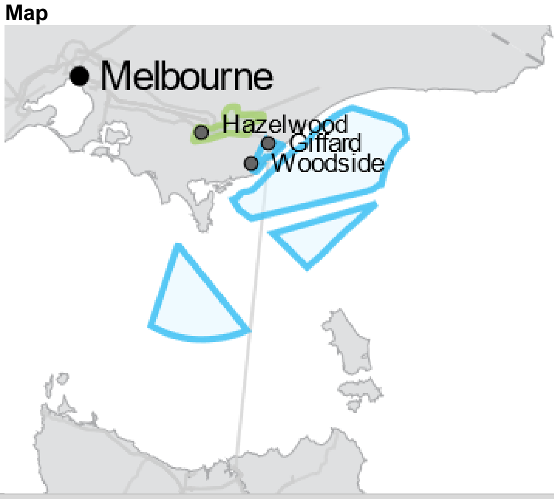
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • Uprating of Portland-Heywood 500 kV double circuit lines Pre-requisite: None	1,000	10 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	None	Long: (12 years)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

4.7.10 SEVIC1 - Group Constraint

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>The group constraint SEVIC1 represents the generation build limit applied to V6, V8 REZs and the Tasmania – Victoria Basslink interconnector. Upgrade options associated with this group constraint may be built to improve the generation capacity in South-East Victoria. These augmentations will facilitate generation transmission to Melbourne load centre.</td><td rowspan="3">Map

</td></tr>
<tr><td>Existing network capability</td></tr>
<tr><td>The network capacity available for SEVIC1 is the same for V6 Gippsland and V8 Gippsland Shoreline.

A security limit of 4,200 MW of VRE, interconnector flow and output from Latrobe Valley generation can be accommodated from Loy Yang to Hazelwood 500 kV substations.

VicGrid is exploring options for increasing this limit as part of options to access offshore wind to support additional capacity.</td></tr>
</table>

<table>
<tr><th colspan="5">Augmentation options</th></tr>
<tr><th>Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>New easement length (km)</th><th>Lead time</th></tr>
<tr><td>Option 1:
• 500 kV double circuit radial line from Loy Yang to Giffard.

Pre-requisite: None</td><td>V8: +2000</td><td>700 to 1,500[165]
Class 5
(+100%/-50%)
[VicGrid value subject to adjustment and risk section notes below]</td><td>55</td><td>Medium: (6 years)</td></tr>
<tr><td>Option 2:
• Second 500 kV double circuit radial line from new terminal station near Woodside to new terminal station near Hazelwood.

Pre-requisite: SEVIC1 Option 1</td><td>V8: +2000</td><td rowspan="2">700
Class 5
(+100%/-50%)
[VicGrid value subject to adjustment and risk section notes below]</td><td>TBC</td><td>Medium: (7 years)</td></tr>
<tr><td>Option 3:
• Tie-in loop between Giffard and new terminal station near Woodside (500 kV double circuit line linking the two Gippsland radial lines).

Pre-requisite: SEVIC1 Options 1 and 2</td><td>V8: +3000
SEVIC1: +4,600</td><td>TBC</td><td>Long: (12 years)</td></tr>
</table>

<table>
<tr><th colspan="3">Adjustment factors and risk</th></tr>
<tr><th>Option</th><th>Adjustment factors applied</th><th>Known and unknown risks applied</th></tr>
<tr><td>Option 1:</td><td colspan="2">Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.</td></tr>
<tr><td>Option 2:</td><td colspan="2">Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.</td></tr>
<tr><td>Option 3:</td><td colspan="2">Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.</td></tr>
</table>

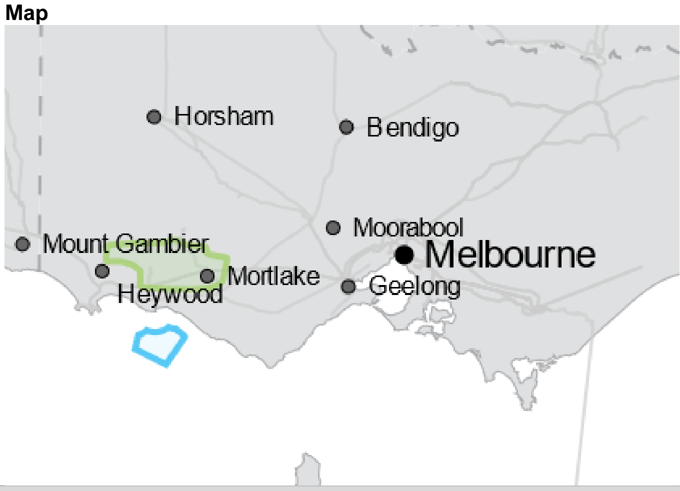
[165] AEMO is joint planning with VicGrid to incorporate a single cost estimate for the final 2025 *Electricity Network Options Report*, rather than a range.

4.7.11 SWV1 - Group Constraint

Summary

The group constraint SWV1 represents the generation build limit applied to V5, V9 REZs and the VIC-SESA Heywood interconnector. Upgrade options associated with this group constraint may be built to improve the generation capacity in South-West Victoria. These augmentations will facilitate generation transmission to APD and Melbourne loads.

Map



Existing network capability

The network capacity available for SWV1 is the same as for V5 South West Victoria and V9 Portland Coast.

Under the ISP preparatory activities function, AEMO Victoria Planning is considering additional options across SWV1.

Augmentation options and outcomes from the preparatory activity report have been incorporated below.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1A: • New 500 kV double-circuit line strung on one side from Mortlake – Moorabool. • Sydenham line uprating. Pre-requisite: MEL-WNV Option 1 or 2	1,500	1,175 Class 5b(±50%)	152	Long: (7 years)
Option 1C: • Heywood- Mortlake 500 kV double-circuit line, strung on one side. Pre-requisite: MEL-WNV Option 1 or 2	1,750	813 Class 5b(±50%)	99	Long: (7 years)
Option 2B: • New Mortlake – Bulgana 500 kV double circuit Pre-requisite: MEL-WNV Option 1 or 2	2,900	550 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	114	Long: (7 years)
Option 3A: • New Heywood - Bulgana 500 kV double-circuit, strung on one side. • New Alcoa Portland - Heywood 500 kV double circuit, strung on one side Pre-requisite: MEL-WNV Option 1 or 2	1,800	2,111 Class 5b(±50%)	203	Long: (7 years)
Option 3C: • String other side of the New Heywood - Bulgana 500 kV. Pre-requisite: SWV1 Option 3A	1,000	359 Class 5b(±50%)	178	Long: (7 years)
Option 3B: • New Heywood - Bulgana 500 kV double-circuit • New Alcoa Portland - Heywood 500 kV single circuit Pre-requisite: MEL-WNV Option 1 or 2	2,800	1,736 Class 5b(±50%)	191	Long: (7 years)
Option 4: • New 500kV double circuit line from Tarrone - Mortlake - Moorabool, and turn in of Heywood - Mortlake 500 kV at Tarrone. Pre-requisite: MEL-WNV Option 1 or 2	2,850	880 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	200	Long: (7 years)

Option 5: • New Heywood – Tarrone 500 kV double circuit. Pre-requisite: MEL-WNV Option 1 or 2	TBC[166]	240 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	15	Long: (7 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1A	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 1C	Delivery timetable: Optimum Project network element size: 5 to 100 km/# of total Bays 1 - 5 Jurisdiction + Land use: VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 2B	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 3A	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 3C	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 1 - 5 Jurisdiction + Land use: VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Outage restrictions: High Others: BAU Unknown Risk: Class 5b
Option 3B	Delivery timetable: Optimum Project network element size: 100 to 200km/# of total Bays 6 - 10 Jurisdiction + Land use: VIC - South West - Grazing Location (regional/distance factors): Regional	Known Risks: Market activity: Tight Others: BAU Unknown Risk: Class 5b
Option 4	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	
Option 5	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

[166] AEMO is joint planning with VicGrid to determine the additional capacity provided by this option for the final *Electricity Network Options Report*

4.7.12 V3-WEST - Secondary Transmission Limit - Eastern Victoria

Summary
V3 and V4 share the same network capacity, this group constraint captures the contribution of both REZs to the need for network upgrades. In previous ISPs, this group constraint was the V3-West Secondary transmission limit
Existing network capability
Combined output from these REZs is 780 MW in summer, and 980 MW in winter.

Map

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**New easement length (km)**	**Lead time**
Option 1: • Rebuild existing single circuit to high-capacity 220 kV double circuit from Murra Warra to Horsham to Ballarat	600	680 Class 5 (+100%/-50%) [VicGrid value subject to adjustment and risk section notes below]	225	Long (9 years)

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	Estimate provided by VicGrid. AEMO (National Planning) will apply an unknown risk uplift of approximately 30% before applying these costs in the ISP.	

5 Distribution network opportunities

The distribution network will play an increasingly important role, linking individual consumers, their CER such as rooftop solar and household batteries, and other distributed resources into one integrated power system. New investment in these electricity networks will be essential to efficiently provide consumers with access to secure and reliable energy, and enable a net zero economy. As consumers continue to connect CER, and if they allow these resources to be well coordinated, they will help deliver reliable and secure energy, at lower cost for all consumers, and contribute to lower emissions.

The capability of the existing distribution network and scale of network upgrades to export more CER are new important inputs to the 2026 ISP. A key outcome of AEMO's ongoing consultation with DNSPs has been the DNSPs providing AEMO with detailed information on the capacity, constraints, alleviation costs and development opportunities within their networks. This significant effort from the DNSPs will enable AEMO to undertake the process outlined in Section 2.12 to approximate the capability of distribution networks to accommodate increased CER penetration and the scale of investments in distribution to support the integration of other distributed resources.

AEMO has received distribution network data for over 500,000 low voltage distribution assets for this report. AEMO thanks each DNSP for their extensive efforts to provide this data as well as the high level of engagement throughout this process for the 2026 ISP, in advance of the release of the demand-side factors guideline consultation by AEMO[84].

This section outlines the summary of distribution network data and cost estimates received from DNSPs and how AEMO proposes to incorporate this into the 2026 ISP:

- Distribution network capacity data (Section 5.1).
- Distribution network augmentation costs (Section 5.2).

5.1 Distribution network capacity data

Distribution network infrastructure plays a crucial role in connecting those who produce and consume electricity across the NEM. However, there are varying limitations in the granularity of data available to DNSPs, and the completeness of data that can therefore be utilised in the ISP. There was a broad range in the scope and detail of the data provided under the Standard Pathway by DNSPs (see Section 2.12.5). For example, a majority of DNSPs were able to provide both the name plate capacity of distribution substations and the maximum export capacity of those substations (often lower due to voltage constraints), but some were only able to provide the former.

To determine a threshold up to which any augmentation options are valid for each network, analysis of the provided DNSP Asset Data Template responses was undertaken to determine typically how much Distribution Substation Site Capacity is limited by voltage constraints before thermal issues arise. The options are predominantly aimed at addressing voltage management concerns and involve technology investment, and therefore this threshold would provide the upper limit on the amount of capacity that could be unlocked via an initial tranche of solutions before an increased level of physical network augmentation would be required to enable exports.

Figure 23 illustrates the distribution substation site capacity data provided by DNSPs and segmented by state. This information presents the rating at a system normal level and the distribution transformer's thermal capacity for continuous operation[167]. This subsequently helps define the available export[168] capacity – the maximum reverse power flow that can be evenly distributed along downstream connection points while maintaining the network within its technical thermal limits.

Figure 24 displays a weighted average of components at different circuit capacity levels, showing how capacity changes among the different circuit types by voltages within the distribution network. In this context, the distribution network circuits include overhead power lines and towers, and underground cables, that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. The weighted average is a length-weighted overall circuit MVA rating based on thermal capacity, which produces an overall MVA x km 'carrying capacity' for each voltage class under normal circumstances.

Many DNSPs provided feedback that they identified voltage as the primary driver for CER curtailment. Low voltage systems are designed for densely populated areas but are limited, with challenges associated with voltage rise often due to high rooftop solar contribution. Figure 24 demonstrates the following insights for capacity in the distribution network:

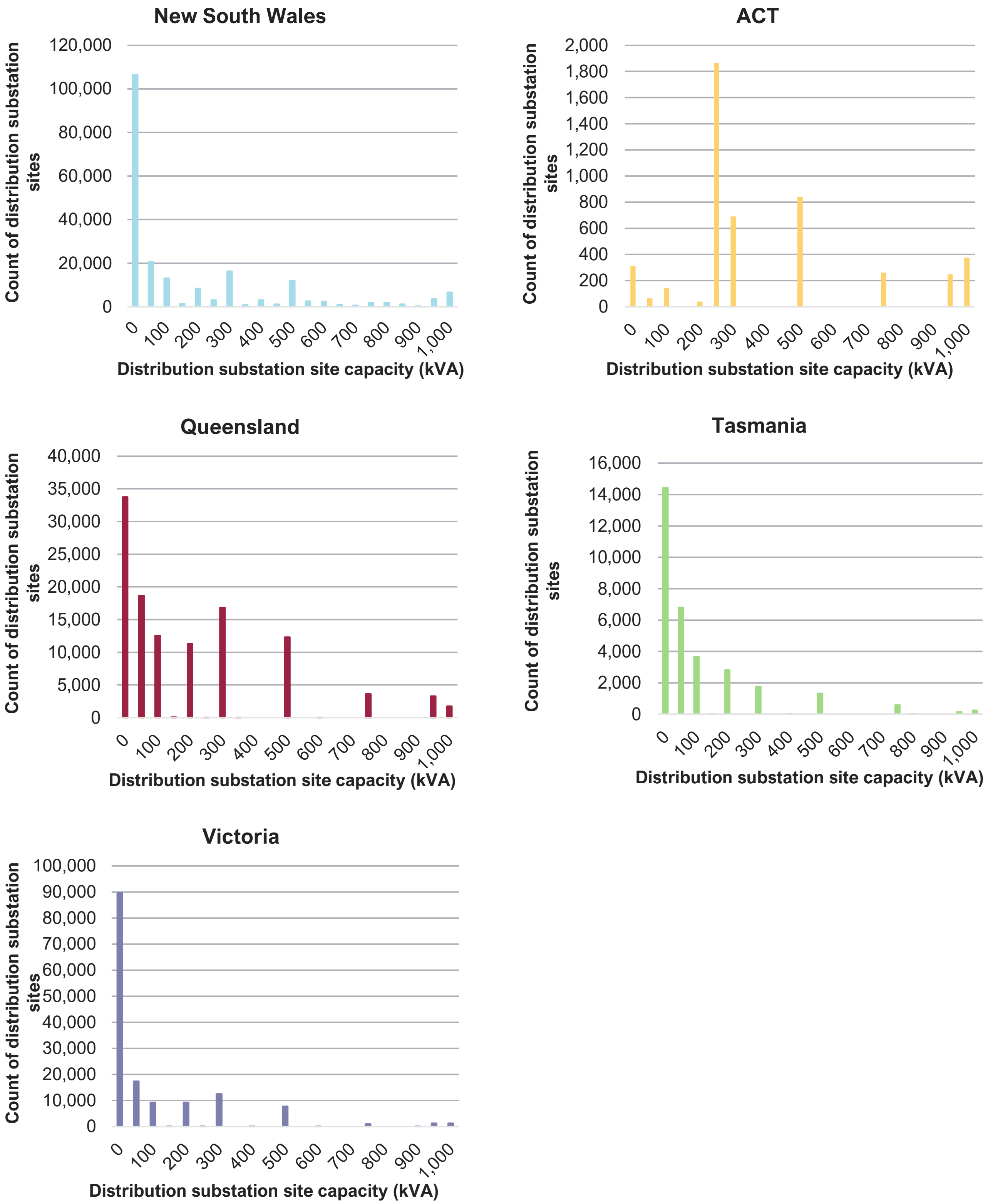
- The higher MVA capacities for the higher voltage classes (66 kV and above) indicate these circuits are more capable of handling larger loads at higher throughput, as HV distribution assets reduce energy losses during transfer of energy and designed for distributing bulk power over longer distances.
- Despite the advantages of HV, most customers still connect CER (residential areas, commercial buildings, and small industrial facilities) to the network at the low voltage level, where capacity is much lower. The lower capacity in low voltage networks means they are more susceptible to thermal and voltage issues, especially with increasing adoption of CER.

Underground lines generally have slightly higher capacities compared to overhead lines at similar voltages (for example, at the 11/22 kV level). Both overhead and underground low voltage assets have significantly lower capacities than HV, validating their intended use which is for shorter distances and smaller loads.

[167] Capacity (in kVA or MVA) is used to determine the maximum power an asset can handle.

[168] Export is defined as power flow in the direction of the upstream transmission network.

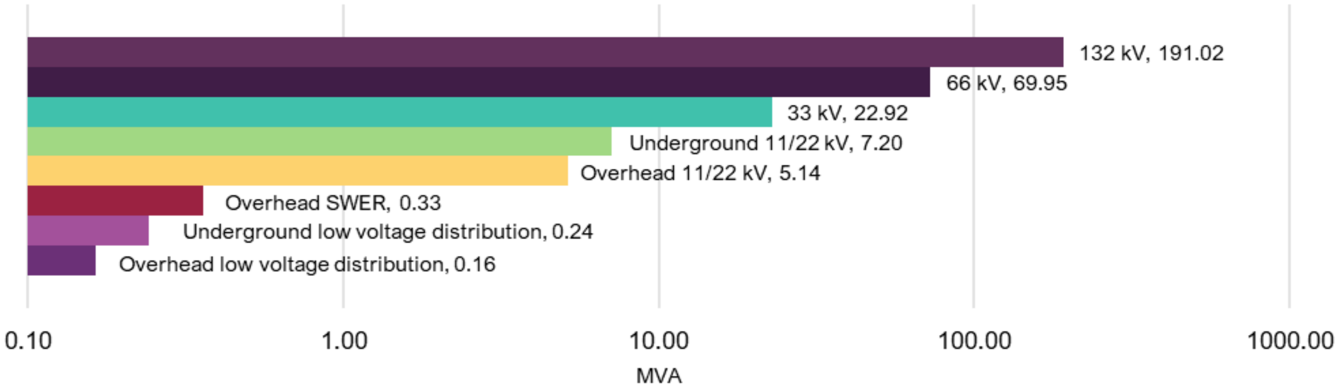
Figure 23 Histogram of DNSP distribution substation site capacity value



Notes:

- Distribution Substation Sites >1,000 kilovolt amperes (kVA) have been included within a single value.
- South Australia is not included here as SA Power Networks has adopted the Alternate Pathway.
- Queensland has excluded 10 kVA and below; this resulted in a reduction in the count of sites within Queensland.

Figure 24 Overhead and underground weighted average MVA circuit capacity by voltage class



Notes:

- Single Wire Earth Return (SWER): a single line conductor connected to the distribution system in remote rural areas.
- Overhead: these include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.
- Underground: this includes cables, cable joints and other assets used to connect the underground network to the overhead system.
- Low voltage distribution refers to circuit assets with voltage lower than 11 kV. Note that the weighted average capacity values have only been shown for the most widespread voltage levels used within Australia currently – while there are cases of other voltages still being used in limited scale by some DNSPs (for example 6.6 kV), these have been excluded from this chart for clarity.

5.2 Distribution network CER augmentation costs

For AEMO to identify macro-level augmentation and associated investment in the distribution network that could be effective in supporting the integration of more CER and other distributed resources, augmentation cost data about distribution networks is required. For DNSPs, investing to increase low voltage infrastructure capacity can be justified to ensure that their networks can handle growing demand, maintain reliable service for end users and enable more CER export. Networks with lower export limits may require significant upgrades via network augmentation to enhance their export capabilities and manage growing customer solar and other connections.

DNSPs typically plan their investments and upgrades with a five-year to 10-year horizon, focusing on immediate to medium-term needs to meet regulatory requirements and energy objectives. This means the cost estimates prepared by DNSPs as part of their revenue determinations are not on the same time horizon as the ISP planning horizon. In addition, there is considerable variability in costs among different DNSPs, which could be due to regional factors, network characteristics, or existing infrastructure conditions. Aside from this ISP process, data is emerging primarily in the context of setting export tariffs, with the current round of AER regulatory determinations being a first step towards widespread publication of expected network upgrade costs to increase distribution networks' ability to host CER and other distributed resources.

Given the current situation, public data on CER integration strategies has been used to improve the quality of the network augmentation input curves for the ISP model, particularly where there were material gaps in data currently available. AEMO analysed the DNSP template responses alongside the publicly available Tariff Structure Statement supporting network marginal cost models (LRMC models).

Figure 25 presents this data with the five-year regulatory control periods' long-run marginal cost (LRMC) values for DNSPs overlaid with Standard Pathway responses for augmentation costs[169]. It charts the cost to unlock a level

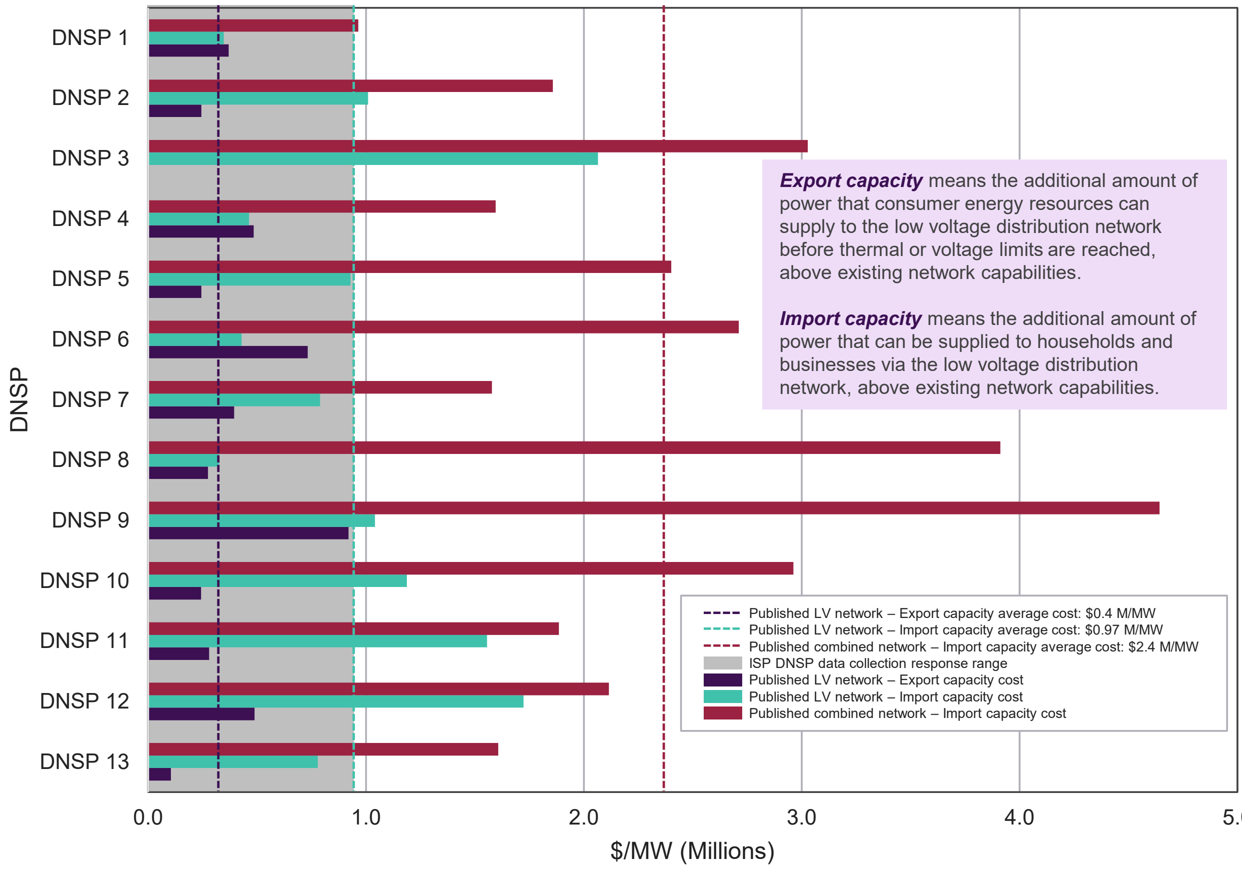
[169] Noting that AEMO's curtailment study is limited to LV only.

of additional export capacity in MW, highlighting the broad range in the cost to add a unit of export capacity for different distribution networks.

The figure highlights the following information:

- The shaded area represents the range of values provided by DNSPs collected as part of the Standard Pathway (see Section 2.12.5).
- The purple bars represent the cost[170] to increase export capacity[171] at the low voltage network level above existing network capabilities.
- The green bars represent the cost to increase import capacity at the low voltage network level above existing network capabilities.
- The red bars represent the combined costs to increase import capacity across all network levels from the low voltage level to transmission (inclusive), above existing network capabilities.
- Average values for each bar are presented by the dotted lines in the relevant colour.

Figure 25 DNSP augmentation cost value analysis



[170] Cost values are listed in LRMC as per AER definition, costs have been converted from annualised values assuming 40-year asset lives and a 5% discount rate.

[171] State average annual PV production curve has been used to convert between exported energy (kWh) and to capacity (kW) capacity per annum.

Overall, the cost for increasing capacity to export energy to the low voltage network (export capacity) is, on average, materially lower than the cost of establishing initial import capacity to households and businesses. This is because in some cases export capacity takes advantage of existing import capacity which can be reconfigured to accommodate export of CER output. In the absence of a detailed locational dataset of costs to enable increased CER output, AEMO considers these export LRMC values to be a suitable measure of the five-year forecast cost of enabling export capacity where that export capacity is primarily focused on managing voltage issues, which are less costly to alleviate than thermal limitations in the network.

AEMO proposes to use the additional export costs and the Standard Pathway responses to form the initial tranche of export enablement with a cost associated with it (Tranche 2) and use the import costs as the upper export enablement cost and for the second tranche with a cost associated with it (Tranche 3), once the lower-cost tranche is exhausted.

It is important to note that this report does not include assessment of how or when the cost tranches would be likely to be accessed in the model – the ISP modelling process for the draft and final ISP processes will include the application of the cost tranches and network limits and consideration of the application of the cost tranches, and will include an optimisation process across the different options available in the NEM. However, AEMO anticipates that the higher-cost tranche (Tranche 3) is unlikely to be accessed frequently in the ISP modelling results for the *Step Change* scenario due to the magnitude of capacity in lower-cost tranches (Tranches 1 and 2) relative to the portion of CER forecasts that could be exported.

Taking into consideration the above, Breakout Box 1 explains the tranches assessed by AEMO and **Table 13** provides the tranche information in a tabular format. As outlined in Section 2.12.8, this proposed cost curve dataset has several tranches, provided for consultation as inputs to the ISP model. Outcomes from applying these tranches will be considered as part of the holistic ISP modelling process. This approach has been prepared in acknowledgement of the fact that precise cost data per DNSP for this purpose is not yet available. AEMO expects that the available data will evolve over successive ISPs.

Breakout Box 1

Tranche 1: Use existing capacity

Tranche Size: The upper limit for this tranche is defined as the lesser of:

1. The sum of distribution substation export capacity, as specified by Distribution Network Service Providers (DNSPs), or
2. Two-thirds (2/3) of the currently installed distribution substation capacity, assuming even distribution of CER across the distribution substation sites and the downstream network. This value has been identified through assessment of the voltage and thermal constraint characteristics of the distribution networks.

Investment Rate: $0 per MW. This rate reflects the utilisation of currently available, existing network capacity with no immediate capital expenditure.

Tranche 2: Voltage management optimisation

Tranche Size: This tranche encompasses capacity additions from the limit of Tranche 1 up to the DNSPs' total currently installed distribution substation thermal capacity. It assumes that at the specified investment rate, DNSPs can optimise their existing network infrastructure and undertake targeted investments in assets and equipment to enhance network management, tighten voltage bandwidth, thereby unlocking hosting capacity up to their thermal distribution substation limits.

Investment Rate: $400,000 per MW. This figure represents the average export Long-Run Marginal Cost (LRMC) across all NEM DNSPs. The individual DNSP export LRMC values where available, sourced from their latest regulatory reset submissions to the Australian Energy Regulator (AER), ranged from $100,000 to $919,000, with a median of $324,000. Annualised LRMC figures were standardised to a common year, assuming a 40-year asset life and a 5% discount rate.

Tranche 3: Network augmentation

Tranche Size: This tranche represents the capacity additions beyond Tranche 2, where existing network capacity has been fully utilised and optimised. Accommodating further CER export capacity in this tranche necessitates network expansion by DNSPs, including upgrades between the low voltage network and the transmission network.

Investment Rate: $2.4 million per MW. This rate is based on the average import LRMC across all network levels for all NEM DNSPs. The underlying DNSP import LRMC values, obtained from their most recent regulatory reset models provided to the AER, ranged from $960,000 to $4.6 million, with a median of $2.1 million. Where LRMC figures were annualised, they have been brought to a common year, based on a 40-year asset life and a 5% discount rate.

In two cases, individual DNSP cost tranches have been applied, prepared by the DNSP outside of the calculation method above, based on the unique characteristics of the networks.

Table 13 provides the DNSP costs for each of the tranche calculations defined above. The horizontal axis represents the MW of distribution network capacity to support aggregate CER to unlock, and the vertical axis represents the rate of cost up to that MW of capacity. This presents the approximate costs to add additional export capacity for CER. For all DNSPs except Ausgrid and SAPN, these values have been derived using the generic calculation method explained in Breakout Box 1.

Table 13 DNSP tranche ranges as assessed by AEMO

DNSP	Use existing capacity		Voltage management optimisation		Network augmentations	
	Cost ($/MW)	Tranche range (MW)	Cost ($/MW)	Tranche range (MW)	Cost ($/MW)	Tranche range (MW)
Ausgrid[A]	-	0 to 4,760	251,000	4,760 to 7,890	730,000	7,890 to 20,000
AusNet	-	0 to 4,520	400,000	4,520 to 6,720	2,400,000	6,720 to 11,950
CitiPower	-	0 to 1,240	400,000	1,240 to 2,880	2,400,000	2,880 to 8,900
Endeavour Energy	-	0 to 8,170	400,000	8,170 to 12,190	2,400,000	12,190 to 21,860
Energex	-	0 to 12,570	400,000	12,570 to 16,880	2,400,000	16,880 to 30,570
Ergon Energy	-	0 to 6,650	400,000	6,650 to 10,100	2,400,000	10,100 to 18,740
Essential Energy	-	0 to 7,030	400,000	7,030 to 10,790	2,400,000	10,790 to 20,390
Evoenergy	-	0 to 1,520	400,000	1,520 to 2,340	2,400,000	2,340 to 4,500
Jemena	-	0 to 1,980	400,000	1,980 to 3,050	2,400,000	3,050 to 5,820

DNSP	Use existing capacity		Voltage management optimisation		Network augmentations	
Powercor	-	0 to 2,310	400,000	2,310 to 5,260	2,400,000	5,260 to 16,040
SA Power Networks[A]	-	0 to 3,000	90,000	3,000 to 9,000	1,600,000	9,000 to 18,040
TasNetworks	-	0 to 2,520	400,000	2,520 to 3,920	2,400,000	3,920 to 7,600
United Energy	-	0 to 1,340	400,000	1,340 to 3,300	2,400,000	3,300 to 10,650

A. Costs for Ausgrid and SA Power Networks have been provided directly by those DNSPs rather than through application of the calculation method provided in Breakout Box 1, through discussion with AEMO, reflecting the current status of analysis about those networks.

As a result of the earlier distribution network capacity analysis, AEMO will apply a ‘two-thirds rule’ at the network level to determine the amount of zero-cost Tranche 1 capacity available. This rule also sets the remaining one-third of distribution substation site capacity as being able to unlocked through Tranche 2 activities, after the initial zero-cost Tranche 1 has been accessed. This ratio represents the percentage of Distribution Substation Site capacity in a network where the application of voltage management-based solutions for the enablement of export capacity is likely to be valid.

This will set the upper MW capacity limit for the application of the second tranche $/MW capacity rate, after the initial no-cost tranche has been applied. The second tranche (voltage management optimisation) indicates that increasing CER export capacity will cost a DNSP, on average, $0.4 million per MW for the first ‘two-thirds’ of installed nameplate capacity on their network. These **voltage management optimisations,** typically involve software, control systems, or minor operational changes that can deliver additional export capacity with relatively low capital investment.

Where lower-cost measures are insufficient to enable additional export, DNSPs may consider more capital-intensive investments in network infrastructure, through **network augmentations.** AEMO has prepared a proposed approach for this tranche, based on collected data and public data, that shows this as a cost of **$2.40 million per MW** tranche cost assuming all distribution network levels require investment. As noted above, it is not expected that the higher-cost tranche (Tranche 3) will be accessed frequently in the ISP modelling results for the *Step Change* scenario.

Table 14 shows the different types of augmentations DNSPs can deploy.

Table 14 Low and high cost export capacity options

Export capacity option	Cost type	Description
Dynamic Operating Envelopes (DOEs)	Low	DOEs provide dynamic, real-time export limits based on prevailing network conditions, allowing greater export flexibility without compromising safety or performance. The cost of implementing DOEs varies depending on a DNSP’s existing level of network monitoring and visibility.
Closed Loop Voltage Control / Dynamic Voltage Management Systems (DVMS)	Low	These systems automatically regulate voltage across the network by adjusting network devices in real-time, helping to maintain voltage stability during high export periods.
Off-Load Tap Optimisation	Low	Off-load tap changers on distribution transformers can be manually adjusted, sometimes as part of planed outages, to better align with expected solar export patterns and reduce voltage rise issues.
Load-Shifting Tariffs	Low	Time-of-use tariffs or other dynamic pricing mechanisms can incentivise customers to shift controllable loads—such as electric hot water heating—to midday periods when solar output is high.

Export capacity option	Cost type	Description
Static Synchronous Compensators (STATCOMs)	Low	STATCOMs enhance voltage control on low-voltage networks by dynamically injecting or absorbing reactive power. This helps manage voltages during both high demand and high solar export conditions.
Phase Rebalancing	Low	Realigning customer and generator connections across phases can reduce voltage imbalances and maximize the use of existing infrastructure.
Transformer Upgrades	High	Replacing existing transformers with units of higher capacity allows the network to accommodate larger power flows from distributed solar generation.
Local Battery Storage	High	Community or grid-connected batteries can absorb surplus solar exports and discharge energy during periods of peak demand, helping to manage voltage and defer traditional upgrades.
Distribution Substation On-Load Tap Changers (OLTCs)	High	Installing OLTCs at distribution substations enables automated, real-time voltage regulation in response to changing export and load conditions.
Overhead Line or Underground Cable Replacement	High	Upgrading overhead lines or underground cables increases current-carrying capacity and reduces voltage rise, enabling more PV export from connected households and businesses.
Network reconfiguration and upgrades	High	These maybe a blended project of reconfiguring the normal network configuration with additional, switches or transformers and targeted asset upgrades. Typically with the goal of reducing the length of network between customer connection points and their upstream transformer

Therefore, over the ISP forecast period, the limit on the addition of export capacity to enable more CER is a doubling of the distribution network's underlying physical capacity, which would represent a simplistic 2x to 4x change in current export capacity. AEMO assumes economically efficient solutions apply to Tranche 2 only, while Tranche 3 assumes more extensive augmentation is needed at all network levels, and is unlikely to be frequently accessed by the ISP model.

The ISP sets out a clear path to transition to a net zero economy by 2050. In parallel with developing the 2026 ISP, AEMO will consult on a new demand side factor information guideline, which will improve the consistency and availability of distribution network information used in subsequent ISPs. AEMO considers that requesting and analysing this data will enable DNSPs to identify areas for improvement and prioritise upgrades that offer the most significant energy system benefits. This data-driven approach ensures that ISP investments are aligned with long-term goals and regulatory requirements, supporting the energy transition.

Consultation questions

15. Do you agree with the proposed DNSP cost tranches and the methodology AEMO has used to identify these? If not, do you have recommendations for how the methodology can be enhanced?

6 Generation and storage connection costs

This section considers the costs associated with the physical network elements required to connect individual generators to the broader network. These considerations are in addition to the flow path and REZ considerations in the previous sections of this report.

Section 6 outlines:

- generator connection costs (Section 6.1)
- treatment of system strength costs for the ISP (Section 6.2), and
- offshore REZ connection costs (Section 6.3).

Consultation questions

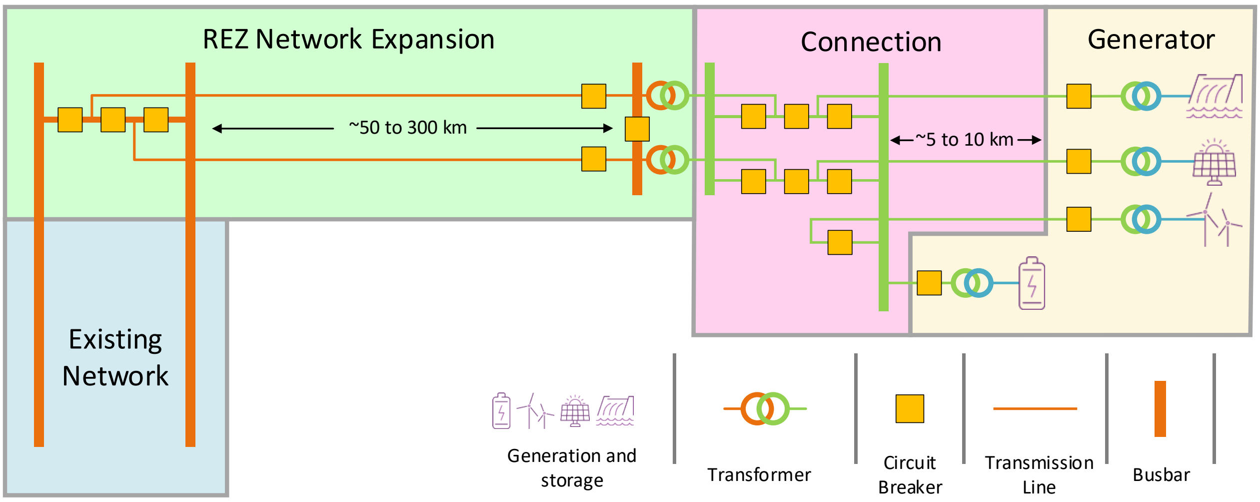
16. What feedback do stakeholders have about the proposed treatment of generation and storage connection costs, including treatment of system strength costs?

6.1 Generator and storage connection costs

Connection costs are added to generator costs to account for the transmission infrastructure required to connect a generator within a REZ to a REZ network, and for connection of other generators and storage. The connection costs vary depending on the proximity to transmission assets and the voltage of the network.

Figure 26 illustrates how connection costs are defined in relation to the REZ network augmentation costs.

Figure 26 Connection cost representation



Note: the generator transformation may include more than one step up transformer.

The proximity of the generation to the transmission network is assumed to vary depending on the generator technology. Due to resource location, wind, solar and pumped hydro projects will often be located 5-10 km from the existing network, or assumed network developed as part of a REZ. The connection cost of battery storage is lower than other storage and generation options because battery storage has more flexibility in its location and can leverage the connection assets used in connecting VRE.

Table 15 describes the parameters of the connection assets used for solar and wind generation connecting in each REZ. **Table 16** describes parameters for other generation technologies which are close to the network. **Table 17** describes parameters for batteries which require no feeder.

Table 15 Connection costs for solar and wind generation technologies

REZ names	Region	REZ network voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($ million)	Cost ($/kW)
Far North Queensland	QLD	275	300	5	52	173
North Queensland Clean Energy Hub	QLD	275	300	10	70	233
Northern Queensland	QLD	275	300	5	52	173
Isaac	QLD	275	300	5	46	153
Barcaldine	QLD	275	300	10	59	196
Fitzroy	QLD	275	300	5	46	153
Wide Bay	QLD	275	300	5	50	167
Darling Downs	QLD	275	300	5	49	163
Banana	QLD	275	1,800	144	839	466
Collinsville	QLD	275	300	5	46	153
North West New South Wales	NSW	330	400	10	72	180
New England	NSW	330	400	10	72	180
Central-West Orana	NSW	330	400	10	75	188
Broken Hill	NSW	220	250	10	56	224
South West New South Wales	NSW	330	400	10	75	188
Wagga Wagga	NSW	330	400	10	75	188
Tumut	NSW	330	400	5	58	145
Cooma-Monaro	NSW	330	400	5	58	145
Hunter-Central Coast	NSW	330	400	5	54	135
Hunter Coast	NSW	N/A*	N/A*	N/A*	N/A*	N/A*
Illawarra Coast	NSW	N/A*	N/A*	N/A*	N/A*	N/A*
Illawarra	NSW	330	400	5	55	138
South Cobar	NSW	330	400	10	69	173
North West Victoria	VIC	220	250	5	44	176
Central Highlands	VIC	220	250	5	44	176
Grampians Wimmera	VIC	220	250	5	44	176
Wimmera Southern Mallee	VIC	220	250	5	44	176

REZ names	Region	REZ network voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($ million)	Cost ($/kW)
South West Victoria	VIC	500	600	10	121	202
Gippsland	VIC	220	250	10	71	284
Central North Victoria	VIC	220	250	10	66	264
Gippsland Coast	VIC	N/A*	N/A*	N/A*	N/A*	N/A*
Portland Coast	VIC	N/A*	N/A*	N/A*	N/A*	N/A*
South East South Australia	SA	275	300	10	74	247
Riverland	SA	275	300	10	74	247
Mid-North South Australia	SA	275	300	5	53	177
Yorke Peninsula	SA	275	300	5	48	160
Northern South Australia	SA	275	300	5	64	213
Roxby Downs	SA	275	300	10	61	203
Eastern Eyre Peninsula	SA	275	300	10	62	207
Western Eyre Peninsula	SA	275	300	10	62	207
North East Tasmania	TAS	220	150	5	50	333
North West Tasmania	TAS	220	150	5	50	333
Central Highlands	TAS	220	150	5	50	333
North Tasmania Coast	TAS	N/A*	N/A*	N/A*	N/A*	N/A*
Non REZ Victoria	VIC	500	600	20	205	342
Non REZ NSW	NSW	500	600	20	177	295
Adjustment factors and risk						
All options	• Location (regional/distance factors): Regional • Project network element size: no. of total Bays 1-5 • Jurisdiction: unique to REZ location			• Known risks: BAU • Unknown risks: Class 5		

* Connection costs already included in the generation cost

Table 16 Connection costs for other generation technologies (excluding batteries)

Connection voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($ million)	Cost ($/kW)
500	600	1	46	77
330	400	1	40	100
275	300	1	35	117
220	250	1	32	104
Adjustment factors and risk				
All options	• Project network element size: no. of total Bays 1-5, 1 to 5 km		• Known risks: BAU • Unknown risks: Class 5	

Table 17 Connection costs for batteries

Connection voltage (kV)	Connection capacity (MVA)	Total cost ($ million)	Cost ($/kW)
500	600	36	60
330	400	33	83
275	300	29	97
220	250	26	104
Adjustment factors and risk			
All options	• Project network element size: no. of total Bays 1-5	• Known risks: BAU • Unknown risks: Class 5	

6.2 System strength costs

The provision of system strength services to facilitate operation of VRE is a complex requirement that is related to system strength available from the broader power system, nearby network upgrades, and the scale of local inverter-based resources (IBR). As such, AEMO applies system strength service costs as a post-processed value in the ISP model rather than modelling this in detail in the power system modelling process.

AEMO will include an estimate of system strength remediation costs in the ISP modelling of generator retirements (to maintain minimum secure levels), and in the development of new IBR and REZs (to support the stable operation of this IBR). Together, these costs will form part of the ISP optimisation, reflecting the need for the power system to continue to meet the current system strength standards.

These synchronous condenser costs are used to update the system security costs shown in the ISP Inputs and Assumptions. Costs shown include synchronous condensers, site works and buildings, step up transformers, and high voltage connection assets. The addition of flywheels for high-inertia synchronous condensers incurs an additional $8 million cost.

Table 18 System strength services cost options

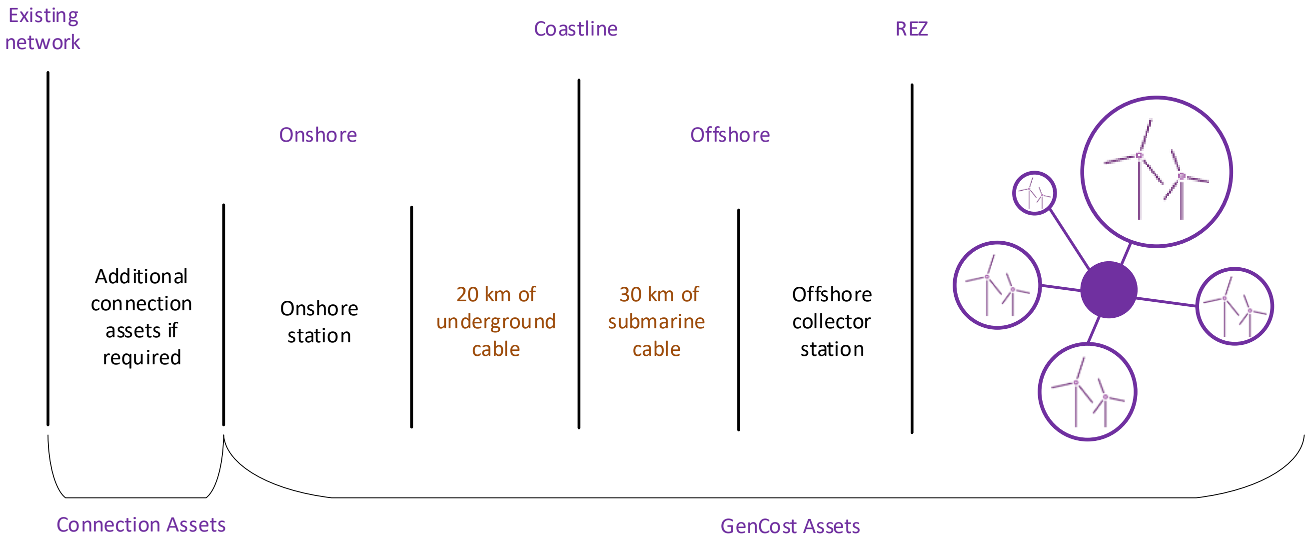
Description	Expected cost ($ million)	Cost classification	Lead time
80 MVA synchronous condenser	138	Class 5b (±50%)	Medium
125 MVA synchronous condenser	185	Class 5b (±50%)	Medium
250 MVA synchronous condenser	323	Class 5b (±50%)	Medium
Adjustment factors and risk			
All options	• Greenfield or Brownfield: Partly Brownfield • Location (regional/distance factors): Regional • Project network element size: no. of total Bays 1-5	• Known risks: Project Complexity was judged as partly complex due to the level of detailed studies required. • Unknown risks: Class 5b	

6.3 Offshore renewable energy zone design

The ISP model includes offshore REZs to connect offshore generation resources off the coast of Australia to the mainland NEM. AEMO is aware of international projects, either being progressed to commissioning or in service, where offshore generation is connecting to mainland transmission networks using a variety of transmission solutions including HVAC and HVDC assets.

For the ISP, it is important to consider what is already factored in when it comes to generation costs. **Figure 27** illustrates the asset inclusion from GenCost and identifies where additional network assets may be required to connect offshore wind to the NEM. The GenCost assumptions for offshore wind include the offshore network assets up to a substation 20 km inland. Additional network assets are required when the existing network assets are further than 20 km from the coast. This additional network is considered a connection asset in the ISP, rather than a REZ augmentation option, as it is dedicated to connecting to offshore generation.

Figure 27 Offshore renewable energy zone design and connection to existing network



For some offshore REZs, no additional connection assets are required to the existing network. Examples include Portland Coast in Victoria or Illawarra Coast in New South Wales, where the existing network is within 20 km of the coast. As a result, much of the connection cost is already considered in the generation cost and the connection cost for these offshore REZs is zero.

For other coastal REZs like V8 Gippsland Coast in Victoria, existing network is further than 20 km from the coastline and additional connection assets are required to bridge between the offshore generation assets and the existing network or REZ network augmentation option. For these REZs, the cost of additional transmission is included either as a connection cost or with augmentation options.

6.4 Connecting distributed resources

Previously shown generator connection costs use cost data from the AEMO Transmission Cost Database to calculate potential connection costs at different voltage levels. As this database contains costs relating to transmission network elements, it cannot be used to determine distribution level costs. To compare different generation connection options between transmission and distribution, an estimate for generation connection costs in the distribution network is also required.

For this reason, when preparing the generation cost estimates for distributed resources, AEMO did this on the basis of also including typical distribution connection costs within the total generator cost estimates. Further details are available in the Aurecon report published for consultation alongside this Draft 2025 *Electricity Network Options Report.*

AEMO welcomes stakeholder feedback and will engage closely with DNSPs to discuss these proposed values between the release of the draft and final 2025 *Electricity Network Options Report*.

List of tables and figures

Tables

Figures

A1. Cost classification checklist

The checklist developed by AEMO for review of the TNSP estimates is shown below.

Class sub-category	Class 5 'b'	Class 5 'a'	Class 4	Class 3	Class 2/1
Scope of works – line, station, cable					
Voltage defined?	Yes	Yes	Yes	Yes	Yes
Rating (MVA, MW, MVAr) defined?	Yes	Yes	Yes	Yes	Yes
Conductors specified?	Yes	Yes	Yes	Yes	Yes
Connection locations (substation, terminal station, converter) defined?	Yes	Yes	Yes	Yes	Yes
Which option best describes the maturity of the routing?	Preliminary Corridor	Preliminary Corridor	High Level Route	Detailed Route	Detailed Route
Have gas network avoidance measures been included?	No	No	No	Yes	Yes
Which option best describes the consideration of national parks?	None	None	High Level	Detailed	Detailed
Which option best describes the consideration of cultural heritage?	None	High Level	High Level	Detailed	Detailed
Which option best describes the consideration of environmentally sensitive areas?	None	High Level	High Level	Detailed	Detailed
Underground lines defined?	No	No	No	Yes	Yes
Which option best describes the maturity of the design?	Concept/ High Level	Concept/ High Level	Preliminary	Detailed/ Complete	Detailed/ Complete
Which option best describes the maturity of the scope?	Concept	Screening	Preliminary	Detailed/ Complete	Detailed/ Complete
Which option best describes the documentation prepared?	-	Conceptual Single Line Diagram	Detailed Single Line Diagram	For Construction/ Civil Diagrams	For Construction/ Civil Diagrams
Level of site investigation for stations/ substations/converters/terminal stations?	Desktop	Desktop	Desktop	Preliminary Site Investigation	Detailed Investigation
Has site remoteness been incorporated into the scope of works?	Yes	Yes	Yes	Yes	Yes
Which option best describes the geographical location of any stations/substations included?	Assumed	Assumed	General Area Defined	Actual Location Defined	Actual Location Defined
Which option best describes the tower design progress?	Assumption Based	Assumption Based	Preliminary Design	Final Design	Final Design
Sites					
Are there any environmental offsets included based on past experience?	Yes	Yes	Yes	Yes	Yes
Strategy/approach developed to refine environmental offsets complete?	Yes	Yes	Yes	Yes	Yes
Are outage restrictions (specific to line diversions and cut ins) considered?	No	No	No	Yes	Yes
Which option best describes the consideration of brownfield works across the project?	None	None	Indicative	Indicative	Detailed/ Complete
Terrain assessment	Desktop	Desktop	Detailed	Detailed	Detailed
Which option best describes the current level of engagement with landowners?	None	None	None	Community Level	Landowner Level
Project management and delivery					

Class sub-category	Class 5		Class 4	Class 3	Class 2/1
	'b'	'a'			
Which option best describes the level of geotech assessment?	None	None	None	Desktop Assessment	Detailed Assessment
Which option best describes the source of cost estimate for equipment and construction?	Previous Projects	Previous Projects	Single In-house Price	Multiple Quotes	Fixed Contract
Which option best describes the identification and assessment of risk progress?	Concept/ High Level	Concept/ High Level	Preliminary	Preliminary	Detailed/ Complete
Has macroeconomic influence been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has market activity been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has project complexity been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has compulsory acquisition been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has environmental offset been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Have geotechnical findings been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Have outage restrictions been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Have weather delays been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has cultural heritage been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has any allowance been made for unknown scope and technology risk?	Yes	Yes	Yes	Yes	Yes
If yes, please indicate allowance amount as a % of baseline cost					
Has any allowance been made for unknown productivity and labour cost risk?	Yes	Yes	Yes	Yes	Yes
If yes, please indicate allowance amount as a % of baseline cost					
Has any allowance been made for unknown plant procurement cost risk?	Yes	Yes	Yes	Yes	Yes
If yes, please indicate allowance amount as a % of baseline cost					
Has any allowance been made for unknown project overhead risk?	Yes	Yes	Yes	Yes	Yes
If yes, please indicate allowance amount as a % of baseline cost					
Which best describes the level of market engagement?	None	None	Revenue Reset/Project Brief	Pre-Tender	Tender
Regulatory					
Scope of works prepared as part of which regulatory gateway?	Future ISP	Future ISP	PADR	CPA	-
Regulatory model	-	Conventional RIT-T	Conventional RIT-T	Conventional RIT-T	Conventional RIT-T

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 NER have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's CBA Guidelines, or AEMO's ISP Methodology.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the optimal development path (ODP), and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3(b) and includes in the ISP.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	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.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.

Term	Acronym	Explanation
Distributed resources	-	Includes both CER and other distributed resources. Both of these include solar photovoltaic (PV) generation and battery energy storage (BESS) assets, with CER generally understood to be 'behind the meter' and other distributed resources to be 'in front of the meter'. For other distributed resources, these are generally between 100 kW and 30 MW in capacity for solar PV, and between 5 MW and 30 MW for BESS.
Distribution Annual Planning Report	DAPR	DNSPs must publish a DAPR setting out the results of their review for the forward planning period.
Distribution network service provider	DNSP	A business responsible for owning, controlling or operating a distribution network.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and GPG.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Long-run marginal cost	LRMC	A DNSP's forward-looking costs that are responsive to changes in electricity.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Regulatory Information Notice	RIN	A formal notice used to collect information from regulated businesses. This information is used for various regulatory purposes, including making regulatory determinations, monitoring performance, and developing reports.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.
Renewable drought	-	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.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ISP, AEMO has considered three scenarios: *Progressive Change*, *Step Change* and *Green Energy Exports*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.

Term	Acronym	Explanation
Spilled energy	-	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.
Transmission Node Identifier	TNI	TNI codes are four-character codes conceptually representing a Transmission Connection Point (or several at the same bus), where the Distribution Network meets the Transmission Network.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating a transmission network.
Utility-scale or utility		For the purposes of the ISP, 'utility-scale' and 'utility' refer to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of CER, including batteries and electric vehicles.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.