Draft 2023 Transmission Expansion Options Report

May 2023

Draft report for consultation

For the 2024 Integrated System Plan (ISP)

Important notice

Purpose

AEMO publishes this Draft 2023 *Transmission Expansion Options Report* as part of an initiative to improve the accuracy and transparency of transmission expansion options used for the 2024 *Integrated System Plan*. This report supplements the 2023 *Inputs, Assumptions and Scenarios Report* (IASR).

This publication is generally based on information available to AEMO as at April 2023 unless otherwise indicated.

Disclaimer

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Copyright

Version control

Version	Release date	Changes
N/A	N/A	**Draft issued for consultation on 2 May 2023**

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

1 Executive summary

Transmission expansion needs to be explored as part of ensuring that National Electricity Market (NEM) consumers have efficient access to renewable energy and firming resources.

The *Integrated System Plan* (ISP) supports Australia's complex and rapid energy transformation towards net zero emissions, identifying development which will enable low-cost firmed renewable energy along with net beneficial transmission to provide consumers in the NEM with reliable, secure, affordable and sustainable power.

Transmission network expansion is a key part of the assessment, as it will increase the transfer capacity of renewable energy zones (REZs) and the backbone of the interconnected network, thereby delivering the transition at lower cost to consumers.

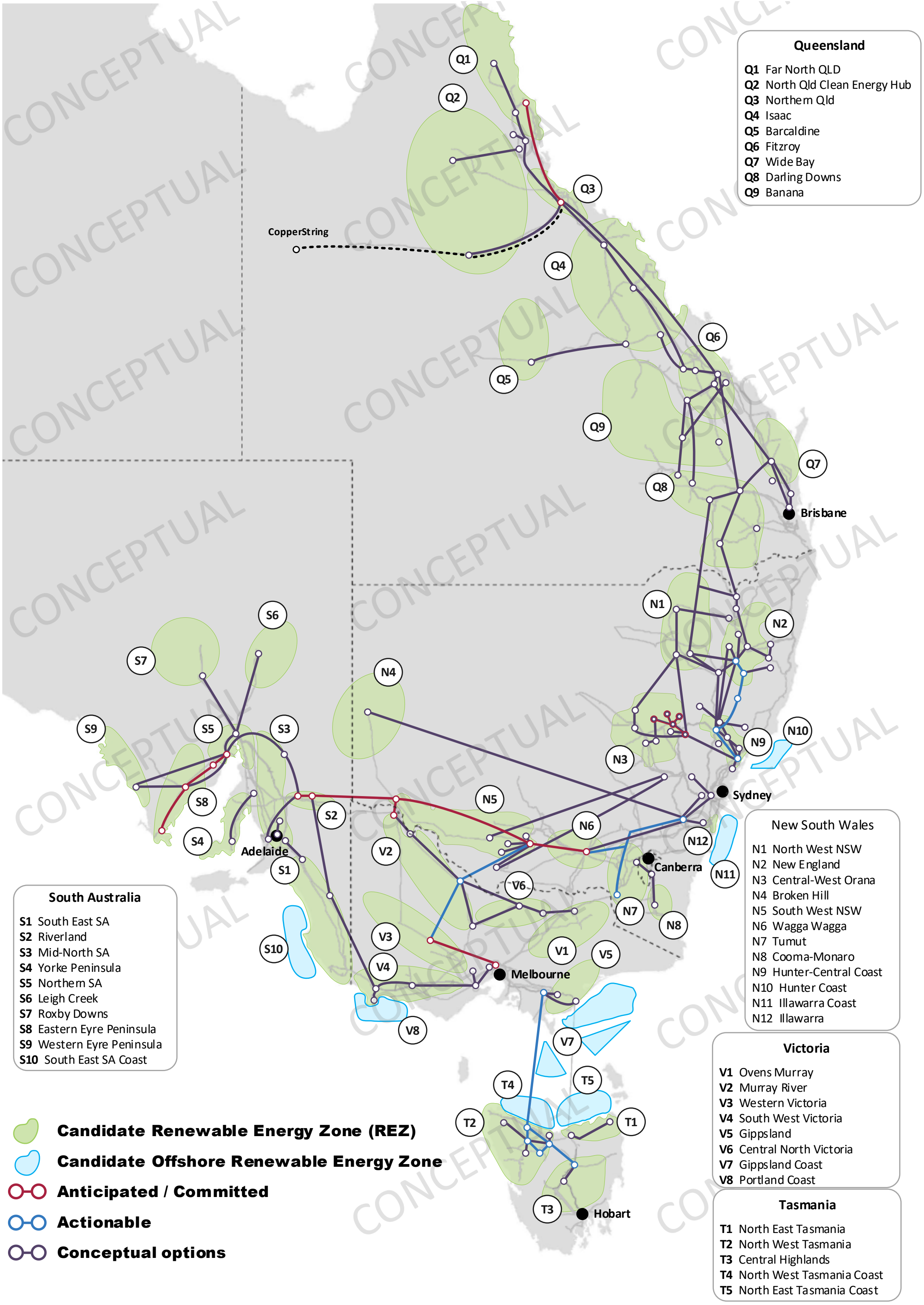
The Draft 2023 *Transmission Expansion Options Report* proposes transmission expansion options to inform the development of the 2024 ISP. AEMO, transmission network service providers (TNSPs) and jurisdictional bodies have undertaken extensive collaboration and joint planning to inform the preparation of this report.

This report includes:

- **Draft transmission expansion options** for the 2024 ISP, including conceptual design, lead time, location and cost estimate.
- **An update to AEMO's Transmission Cost Database,** undertaken by independent consultant Mott MacDonald to reflect the most recent cost estimation processes and data for transmission network assets.
- **A request for feedback on draft transmission expansion options**, including cost, design, lead time and any other matters relating to transmission expansion options proposed for consideration in the 2024 ISP.

Figure 1 provides a map of the REZs and flow path options considered in this report.

Figure 1 Map of REZs and flow path options for Draft 2023 *Transmission Expansion Options Report*



Cost estimates have been updated to reflect supply chain constraints and global competition for electricity infrastructure assets

The Australian power sector continues to be subject to ongoing supply chain issues for delivery of materials and equipment, as well as workforce and skills shortages.

AEMO has commissioned an update to its Transmission Cost Database to ensure that recent cost data can inform the 2024 ISP. The update includes expert cost estimation advice, which has been informed by recent transmission project tendering outcomes in the NEM, and incorporates proposed baskets of indices that may be used for forecasting transmission cost changes over at least the next 20 years. Cost estimates provided in this report generally show around 15-20% increase in costs compared to equivalent cost estimates prepared for the 2022 ISP.

Leveraging industry expertise through stakeholder engagement

AEMO is committed to facilitating a stakeholder engagement process that ensures a consultative approach to developing the 2024 ISP. AEMO welcomes feedback on all matters relating to proposed transmission expansion options in this report.

AEMO collaborates with TNSPs and jurisdictional bodies to co-design conceptual network options for the ISP. AEMO thanks TNSPs and jurisdictional bodies for the close joint planning work undertaken to prepare this Draft 2023 *Transmission Expansion Options Report*.

All stakeholders are invited to provide a written submission to any matters discussed in this draft report, or in the attached consultant's report on the update to AEMO's Transmission Cost Database.

Submissions in response to this Draft 2023 *Transmission Expansion Options Report* should be sent by email to ISP@aemo.com.au, to reach AEMO by 5.00 pm (AEST) on 31 May 2023.

Prior to submissions closing, AEMO will host a 90-minute webinar on Thursday 18 May 2023, from 2.30 pm to 4.00 pm (AEST). At the webinar, AEMO will present the key transmission expansion and cost proposals in this report, and allow time for questions. Stakeholders can sign up to attend the webinar here[1].

[1] At https://events.teams.microsoft.com/event/133999ef-fc8b-41dc-b993-d5f83e39b258@320c999e-3876-4ad0-b401-d241068e9e60.

Consultation questions provided in this paper

Methodology

1. Do you have any feedback on the update to the AEMO Transmission Cost Database? If yes, please provide data and evidence for any suggested enhancements.
2. Do you have any feedback on the proposed approach to forecasting future transmission cost increases? If yes, please provide data and evidence for any suggested enhancements.
3. Do you have any suggested alternatives to AEMO’s approach to considering social licence for transmission projects for the ISP? If yes, what are the alternatives? Please provide information or evidence supporting the use of any alternative approach.
4. Do you have any specific feedback on social licence considerations for the flow paths, REZs or group constraints considered in this report? If yes, please provide information or evidence to support the feedback, where possible.

Flow paths

5. Do you have any feedback on the flow path augmentation options provided in this report, including their conceptual design, lead time, location and cost estimates? Please provide evidence to support your feedback.

Renewable energy zones (REZs)

6. Do you have any feedback on the REZ augmentation options provided in this report, including their conceptual design, lead time, location and cost estimates? Please provide evidence to support your feedback.

Generator connection costs

7. Do you agree with the proposed cost estimation process and outcomes for generator connections in the ISP? If not, why not? Please provide evidence to support your feedback.
8. Do you agree with the proposed cost estimation process and outcomes for system strength costs in the ISP? If not, why not? Please provide evidence to support your feedback.
9. Do you agree with the proposed cost estimation process and outcomes for offshore REZ connections in the ISP? If not, why not? Please provide evidence to support your feedback.

Material changes from the 2021 *Transmission Cost Report*

Compared to the 2021 Transmission Cost Report, AEMO has made the following changes in this Draft 2023 Transmission Expansion Options Report:

- **The document title has been changed** from Transmission Cost Report to Transmission Expansion Options Report to reflect that AEMO is consulting on all facets of the transmission expansion options – including conceptual design, lead time, location and cost estimate.
- **Updated flow path and REZ augmentation 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.
- **Update of the AEMO Transmission Cost Database** to revise attributes and risk allowances, include up to date transmission cost estimates, propose a basket of indices which may be used to forecast transmission cost estimates over at least the next 20 years, and inclusion of additional building block options to ensure the tool remains relevant in the changing technology landscape.
- **Consideration of the Australian Energy Market Commission's (AEMC's) system strength framework rule change** on applying system strength costs to transmission expansion options by proposing a cost estimation process for meeting the 'efficient' level of system strength to facilitate connection of variable renewable energy under the new system strength standard.
- **Consideration of enhancement options on the treatment of social licence** for transmission projects by incorporating joint planning outcomes with TNSPs and jurisdictional bodies, and proposing to incorporate a set of social licence-focused sensitivities in the 2024 ISP modelling process.
- **Updates to project lead time** using information from recent transmission projects and joint planning with TNSPs and jurisdictional bodies.
- **The inclusion of transmission expansion options from jurisdictional policies** including the Queensland Energy and Jobs Plan, the EnergyCo Network Infrastructure Strategy, and updates to Western Renewables Link and Victoria – New South Wales Interconnector (VNI) West.

Contents

Tables

Figures

2 Introduction

AEMO's *Integrated System Plan* (ISP) is a whole-of-system plan that provides a comprehensive roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years. The ISP supports Australia's complex and rapid energy transformation towards net zero emissions, enabling low-cost firmed renewable energy and essential transmission to provide consumers in the NEM with reliable, secure and affordable power.

Leveraging expertise from across the industry is pivotal to the development of a robust plan that supports the long-term interests of energy consumers. AEMO is committed to taking a consultative approach to developing the 2024 ISP. The conceptual design, lead time, lead time and cost estimates for transmission expansion options are vital inputs to the process that determines whether transmission projects should proceed[2].

This Draft 2023 *Transmission Expansion Options Report* forms part of the 2023 *Inputs, Assumptions and Scenarios Report* (IASR). It describes the engagement of independent experts and provision of industry and stakeholder advice, culminating in a draft report summarising the conceptual design, lead time, location and cost estimates for candidate transmission projects for the 2024 ISP. AEMO welcomes feedback on all aspects of this Draft 2023 *Transmission Expansion Options Report*.

This section outlines the context for this report:

- Notice of consultation (Section 2.1).
- Application of this report in the ISP (Section 2.2).
- 2024 ISP development process (Section 2.3).

2.1 Notice of consultation

AEMO is publishing this draft report to consult on the transmission augmentation options under consideration for the 2024 ISP, including conceptual design, lead time, location and cost estimates. This draft report is published as a supporting publication for the 2023 IASR and in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines[3].

Stakeholder submissions are welcomed in response to the Draft 2023 *Transmission Expansion Options Report*

All stakeholders are invited to provide a written submission to any matters discussed in this draft report, or in the attached consultant's report on the update to AEMO's Transmission Cost Database, as well as any other matters that stakeholders consider relevant to the Draft 2023 *Transmission Expansion Options Report*[4].

[2] AEMO is currently consulting on proposed amendments to the ISP Methodology, seeking any stakeholder submissions by 1 May 2023. Information about the consultation is available at https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology. AEMO intends to respond to stakeholder feedback and finalise amendments to the ISP Methodology by 30 June 2023.

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

[4] Consultation material is available at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

Submissions in response to this Draft 2023 *Transmission Expansion Options Report* should be sent by email to ISP@aemo.com.au, to reach AEMO by 5.00 pm (AEST) on 31 May 2023.

Please identify any parts of your submission that you wish to remain confidential, and explain why. AEMO requests that, where possible, submissions should provide evidence and information to support any views or claims that are put forward.

Prior to submissions closing, AEMO will host a 90-minute webinar on Thursday 18 May 2023, from 2.30 pm to 4.00 pm (AEST). At the webinar, AEMO will present the key transmission expansion and cost proposals in this report, and allow time for questions. Stakeholders can sign up to attend the webinar here[5].

AEMO will then host a session on Friday 19 May 2023 from 11.00 am to 12.00 pm AEST for consumer advocates to provide their submissions verbally. Consumer advocates can sign up to attend here[6].

Supplementary materials

Table 1 outlines related files and reports that have been used to determine transmission costs in this Draft 2023 *Transmission Expansion Options Report*. Stakeholders are invited to refer to these documents for further background and context.

Table 1 Related files and reports

Document	– Description	Location
Transmission Cost Database Update Final Report	Describes the update made to the AEMO Transmission Cost Database in 2023 by independent consultant Mott MacDonald.	https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation
Transmission Cost Database version 2.0	Database of cost estimate inputs and cost estimating tool used for estimating future ISP transmission expansion options and, in some cases, where cost estimates are not available from a project proponent. Version 2.0 includes a 2023 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/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation
Draft transmission cost estimate calculations	A compressed ZIP file containing AEMO Transmission Cost Database output files for each project option in the Draft 2023 *Transmission Expansion 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/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation

Next steps

AEMO will host a public webinar on 18 May 2023 following the publication of this Draft 2023 *Transmission Expansion Options Report*. AEMO will consider all feedback and will publish the final 2023 *Transmission Expansion Options Report* on 28 July 2023 as a supporting publication for the final 2023 IASR. Responses to the consultation will be included in the 2023 IASR consultation summary report.

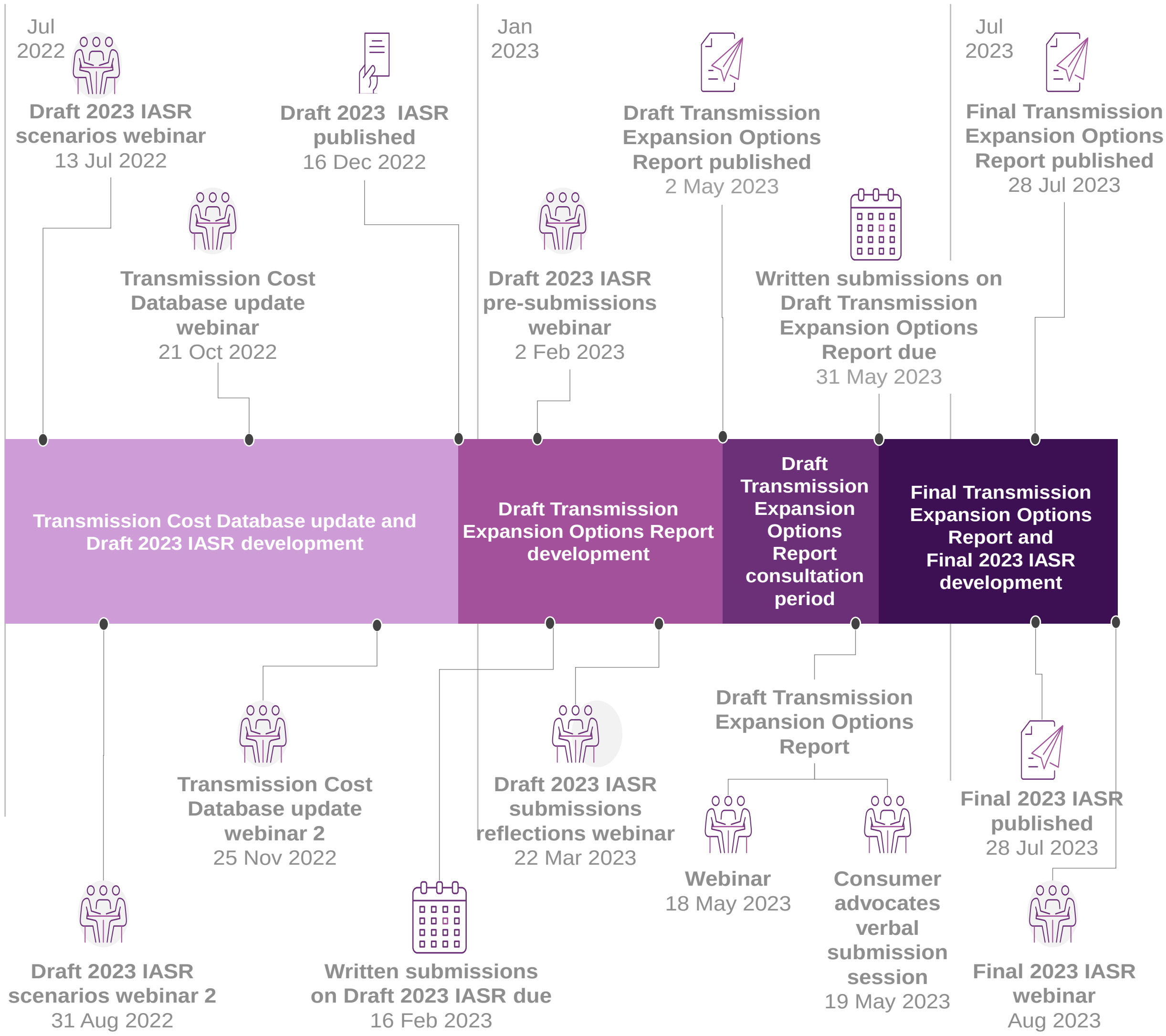
[5] At https://events.teams.microsoft.com/event/133999ef-fc8b-41dc-b993-d5f83e39b258@320c999e-3876-4ad0-b401-d241068e9e60.

[6] At https://events.teams.microsoft.com/event/1c6691a3-3ddc-4b34-923a-ebf7afda6158@320c999e-3876-4ad0-b401-d241068e9e60.

Following publication, AEMO will host a webinar that will cover the final 2023 IASR, including summarising the key changes to the final 2023 *Transmission Expansion Options Report*, summarising key feedback, and outlining how this feedback has been considered. Over the coming months, stakeholders will be able to sign up to attend the webinar here[7].

Figure 2 shows the consultation undertaken so far on the 2023 *Transmission Expansion Options Report*, and next steps.

Figure 2 Consultation stages for the 2023 *Transmission Expansion Options Report*



2.2 Application of this report in the ISP

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 optimal development path (ODP). The ODP identifies new transmission projects that are actionable now as

[7] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

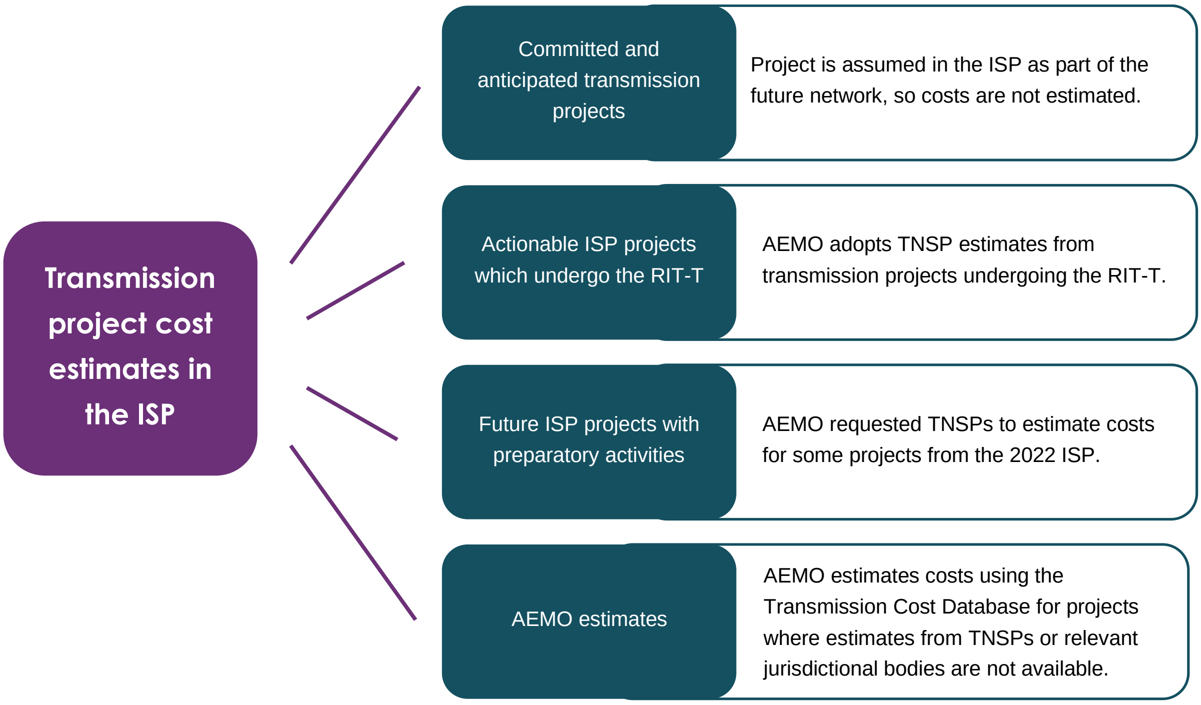
well as in the future, and also includes new generation and storage to efficiently deliver firmed renewable energy to consumers through the NEM[8].

AEMO seeks to co-design conceptual network options for the ISP with transmission network service providers (TNSPs) and NEM jurisdictional bodies. AEMO, TNSPs and jurisdictions have collaborated to undertake the extensive joint planning necessary to prepare this draft report. These bodies include Powerlink, Transgrid, EnergyCo, AEMO in its capacity as the Victoria Transmission Planner, VicGrid, ElectraNet, MarinusLink, TasNetworks, and other relevant jurisdictional bodies. In some cases, this Draft 2023 *Transmission Expansion Options Report* incorporates advice from project proponents for committed and anticipated transmission projects, as well as draft preparatory activities reports requested in the 2022 ISP.

The 2024 ISP will use transmission project options from the final 2023 *Transmission Expansion Options Report*, which will form part of the 2023 IASR. The final 2023 IASR will be released on 28 July 2023, after AEMO considers feedback on this draft report and on the Draft 2023 IASR. Where updated cost estimate information is provided to AEMO by TNSPs for future ISP projects with preparatory activities, and for projects undergoing the Regulatory Investment Test for Transmission (RIT-T) process, AEMO will cross-check this information[9] using the latest Transmission Cost Database before it is included in the final 2023 *Transmission Expansion Options Report* and final 2023 IASR.

Figure 3 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 3 AEMO's approach to incorporating transmission projects in the IASR and ISP



[8] 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/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology. AEMO is currently consulting on updates to the methodology, via a consultation page at https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

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

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[10], and are consistent where relevant with five criteria defined for committed projects in the AER's Cost Benefit Analysis Guidelines[11] and RIT-T[12] instruments.

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 2 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.

Table 2 **Committed and anticipated transmission projects for the 2024 ISP[A]**

Project	Status	Responsible TNSP(s) or jurisdictional bodies	More information
Central-West Orana REZ Transmission Link	Anticipated	EnergyCo	https://www.energyco.nsw.gov.au/cwo.
Eyre Peninsula Link	Committed	ElectraNet	https://www.electranet.com.au/projects/eyre-peninsula-link/
VNI Minor (also named VNI East Upgrade)	Committed	AEMO (Victorian Planning), Transgrid	https://aemo.com.au/initiatives/major-programs/vni-west https://www.transgrid.com.au/projects-innovation/victoria-to-nsw-interconnector
QNI Minor (Queensland - New South Wales Interconnector)	Committed	Transgrid	https://www.transgrid.com.au/projects-innovation/queensland-nsw-interconnector https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity
Northern QREZ	Committed	Powerlink	https://www.powerlink.com.au/queensland-renewable-energy-zones
Project EnergyConnect - Stage 1	Committed[B]	ElectraNet, Transgrid	https://www.electranet.com.au/projects/project-energyconnect/ https://www.transgrid.com.au/projects-innovation/energyconnect
Project EnergyConnect - Stage 2	Committed[B]	ElectraNet, Transgrid	https://www.electranet.com.au/projects/project-energyconnect/ https://www.electranet.com.au/projects/project-energyconnect/

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

[11] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[12] 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.

Project	Status	Responsible TNSP(s) or jurisdictional bodies	More information
Murray River REZ and Western Victoria REZ minor augmentations	Committed	AEMO (Victorian Planning)	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 (Victorian Planning)	Pg. 68, 2022 *Victorian Annual Planning Report*
Mortlake Turn-In	Committed	AEMO (Victorian Planning)	Pg. 68, 2022 *Victorian Annual Planning Report*
Waratah Super Battery Network Augmentations and SIPS Control	Committed	EnergyCo	https://www.energyco.nsw.gov.au/projects/waratah-super-battery
Ararat synchronous condenser	Committed	AEMO (Victorian Planning)	Pg. 69, 2022 *Victorian Annual Planning Report*
Western Renewables Link	Anticipated	AEMO (Victorian Planning)	https://www.westernrenewableslink.com.au/

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.
B. Project Energy Connect has not yet met all five commitment criteria in all three states but is expected to do so by the publication of the final 2023 IASR in July 2023.

Actionable ISP projects which undergo the RIT-T

Actionable ISP projects undergo the RIT-T. The proponent TNSP proceeds through a staged 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.

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 highly uncertain, they are modelled as augmentation options in the ISP (that is, they are not assumed to proceed). AEMO considers that TNSPs 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 TNSPs to ensure uncertainty and risks are applied consistently across investment options.

Table 3 lists the RIT-T projects that will be included in the 2024 ISP. AEMO may also use updated information in the ISP, for example as included in the latest Transmission Augmentation Information publication.

Table 3 RIT-T projects in the 2024 ISP

Project	Responsible TNSP(s)	Section in this report
HumeLink	Transgrid	Section 4.8
VNI West	Transgrid and AEMO (Victorian Planning)	Section 4.9
Marinus Link	TasNetworks, Marinus Link	Section 4.10

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.

Table 4 lists the future ISP projects for which AEMO has required preparatory activities, including cost estimates, from TNSPs. At the time of publication of this report, AEMO has received draft confidential preparatory activities for these future ISP projects. Final preparatory activities reports are due to AEMO by the end of June 2023.

Table 4 Future ISP projects with preparatory activities from the 2022 ISP

Project	2022 ISP timing	Preparatory activities required by	Responsible TNSP(s)	Section(s) in this report
South East SA REZ expansion (Stage 1)	2025-26 to 2045-49	30 June 2023	ElectraNet	Section 5.4.1
Darling Downs REZ Expansion (Stage 1)	2025-26 to 2047-48	30 June 2023	Powerlink	Section 5.3.8
Mid-North SA REZ Expansion	≥ 2028-29	30 June 2023	ElectraNet	Section 5.4.3
QNI Connect (500 kV option)	2029-30 to 2036-37	30 June 2023	Powerlink and Transgrid	Section 4.5
QNI Connect (330 kV option – NSW scope)	2029-30 to 2036-37	30 June 2023	Transgrid	Section 4.5
South West Victoria REZ Expansion	≥ 2033-34	30 June 2023	AEMO (Victorian Planning)	Section 5.6.4

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[13] to cost the transmission expansion project options for which cost estimates have not been developed by TNSPs or jurisdictional bodies. Section 3 provides further information about the update to the AEMO Transmission Cost Database undertaken in preparation for the 2024 ISP.

This report outlines options for transmission augmentation projects. Section 3 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 4.
- **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 5.
- **Generation connection** – generator connection cost matters, including system strength costs, treatment of offshore resource connections, and connection costs for onshore generators – see Section 1.

[13] Version 2.0 of the AEMO Transmission Cost Database, released April 2023, is accessible via https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Register to receive it at https://forms.office.com/r/YbmiGc24TP.

2.3 2024 ISP development process

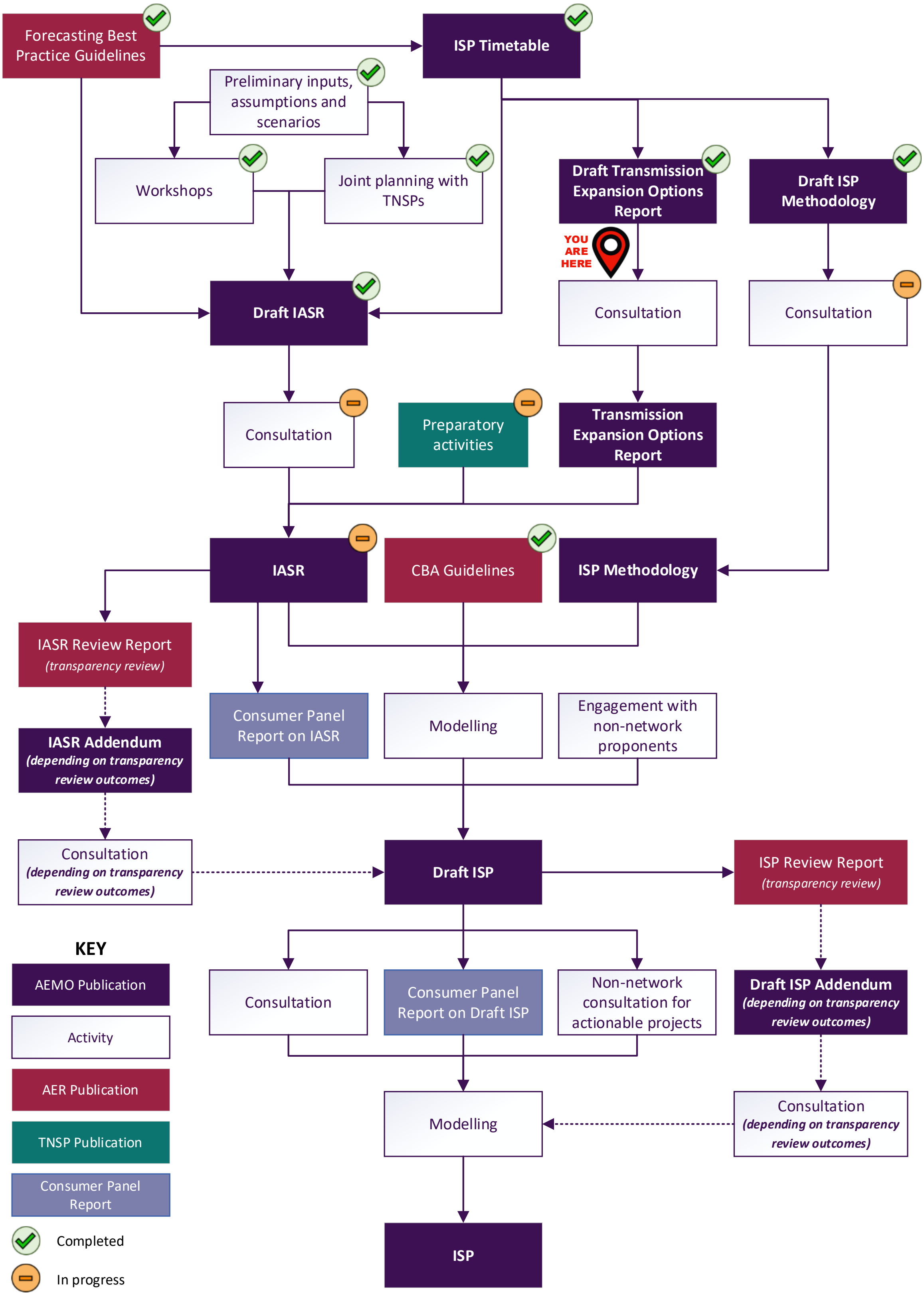
Figure 4 shows the ISP process as a whole and current progress on all elements for the 2024 ISP[14]. In addition to this Draft 2023 *Transmission Expansion Options Report* consultation, two other consultations that will inform the 2024 ISP are underway:

- **The update to the ISP Methodology**[15] will consider eight proposed updates to the methodology which sets out how modelling is applied in the ISP and how cost benefit analysis is used in the ISP. The update includes receiving stakeholder submissions by 1 May 2023, publication of the final update to the ISP Methodology on 30 June 2023, and a webinar on 13 July 2023 to summarise key changes.
- **The 2023 IASR** will catalogue the range of inputs, assumptions and scenarios for the 2024 ISP. At the time of publication of this paper, AEMO has received submissions on the Draft 2023 IASR, has hosted a webinar, and will continue to finalise responses to feedback before publishing the final 2023 IASR in July 2023[8].

[14] The 2024 ISP Timetable provides more information on the key milestones of the 2024 ISP development process, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2024-isp-timetable.pdf?la=en.

[15] AEMO. Consultation on updates to the ISP Methodology. At https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

Figure 4 Navigating the ISP process



Note: The diagram above has been amended from the version published in the 2024 ISP timetable by adding a box containing "Draft Transmission Expansion Options Report" and "Transmission Expansion Options Report" with an additional "Consultation" box. The IASR will consider transmission development options and non-network alternatives.

3 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.

In response to feedback from stakeholders, AEMO initiated a work program after the 2022 ISP to continue to improve the transparency and robustness of the transmission cost estimation process used in the ISP. This included a new Transmission Cost Database which is used to estimate the cost of transmission projects. The process used to estimate transmission project costs is outlined in the following sections, along with a process to ensure consistency with TNSP project estimates.

This section outlines the methodology for assessing transmission augmentation project options:

- Cost estimation framework (Section 3.1).
- AEMO Transmission Cost Database (Section 3.2).
- Review of TNSP cost estimates (Section 3.3).
- Estimating operational expenditure (Section 3.4).
- Economic, social and environmental costs and benefits (Section 3.5).
- Market impacts on transmission costs (Section 3.6).
- Projected changes in infrastructure costs over time (Section 3.7).
- Transmission project lead time (Section 3.8).
- Social licence for transmission projects (Section 3.9).

3.1 Cost estimation framework

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

3.1.1 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 Australian TNSPs, noting that this may vary for individual TNSPs. The content is not prescriptive, and stakeholders are referred to the AER Cost Benefit Analysis Guidelines[16] and RIT-T Application Guidelines[17] for more information.

[16] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

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

Cost estimates progress from a very early stage with little design or information known (least accurate) to a fully costed and engineered estimate built up (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. This system defines a series of 'classes' of estimates, ranging from Class 5 (least accurate) to Class 1 (most accurate). AEMO has adopted the AACE International framework 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:

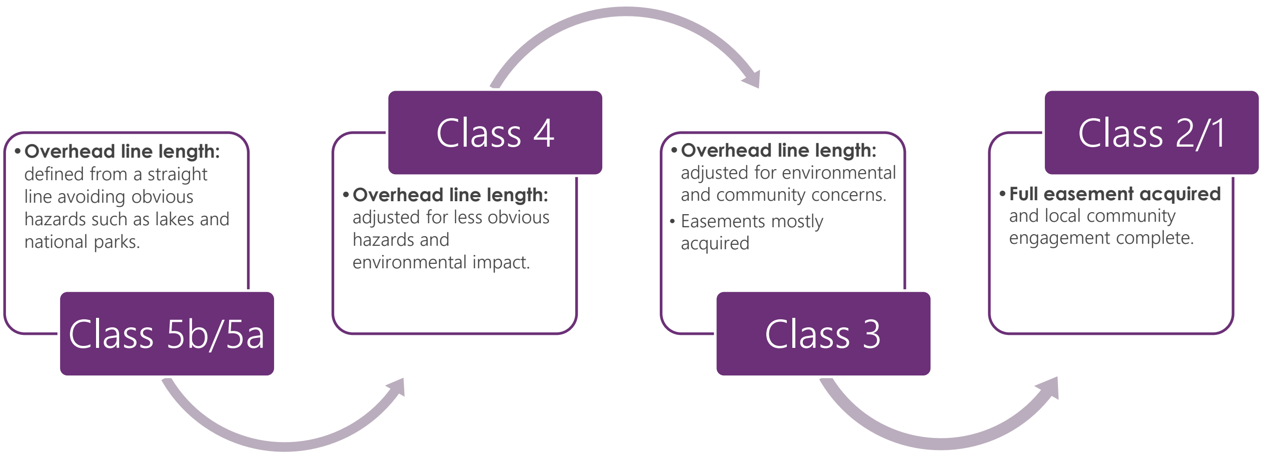
- Class 5b – Concept level scoping with no site-specific review or TNSP input.
- Class 5a – Screening level scoping including high level site-specific review and TNSP input.

Further detail on the associated accuracies of these classes is provided in Section 3.2.2.

Figure 5 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.

Figure 5 Design progress with project maturity – example showing how overhead line length assumption changes



3.1.2 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 5 shows the current steps for ISP projects and outlines the planning and development works that typically take place at each step. The table illustrates the ISP regulatory process; the future ISP projects that are estimated by AEMO, and the other steps are carried out by the TNSPs. Some projects may be developed differently to that shown here, for instance where additional funding is provided.

The indicative class levels shown here reflect AEMO's current understanding of levels typically used at each step, which may vary across the TNSPs and across projects. AER Cost Benefit Analysis Guidelines[18] and RIT-T Application Guidelines[19] outline the expectations for each stage of the RIT-T, however they do not currently stipulate a specific class level for cost estimates, as estimate accuracy achieved at each step will depend on the nature of the project.

Table 5 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
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	• 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	• 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	• 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 finalised apart from micrositing issues • Biodiversity offset liability

[18] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[19] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.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]
		risks and environmental sensitivities • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	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	• Corporate cost budget estimated at a high level	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. 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, the TNSPs typically produce Class 5a or 4 estimates as they become further defined. 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 3.3.

AEMO includes all committed and anticipated projects in all future states of the world, in accordance with the AER's Cost Benefit Analysis Guidelines[20]. Because of this, the capital cost for committed and anticipated projects is not part of the ISP modelling process (similar to the capital cost of existing generation and transmission). Committed and anticipated projects are therefore not described in detail within this report.

3.2 Transmission Cost Database

The Transmission Cost Database was 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

[20] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

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 into these updates. Section 3.2.3 provides information about the 2023 update to the 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 3.2.2, the Transmission Cost Database is intended for use by AEMO to generate Class 5a/b cost estimates for 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.

3.2.1 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.
- 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 in each project table in Section 4 and Section 5 of this report. In addition, the numerical and percentage value of each adjustment factor is presented in the detailed output file for each project[21].

[21] Consultation material is available at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

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.

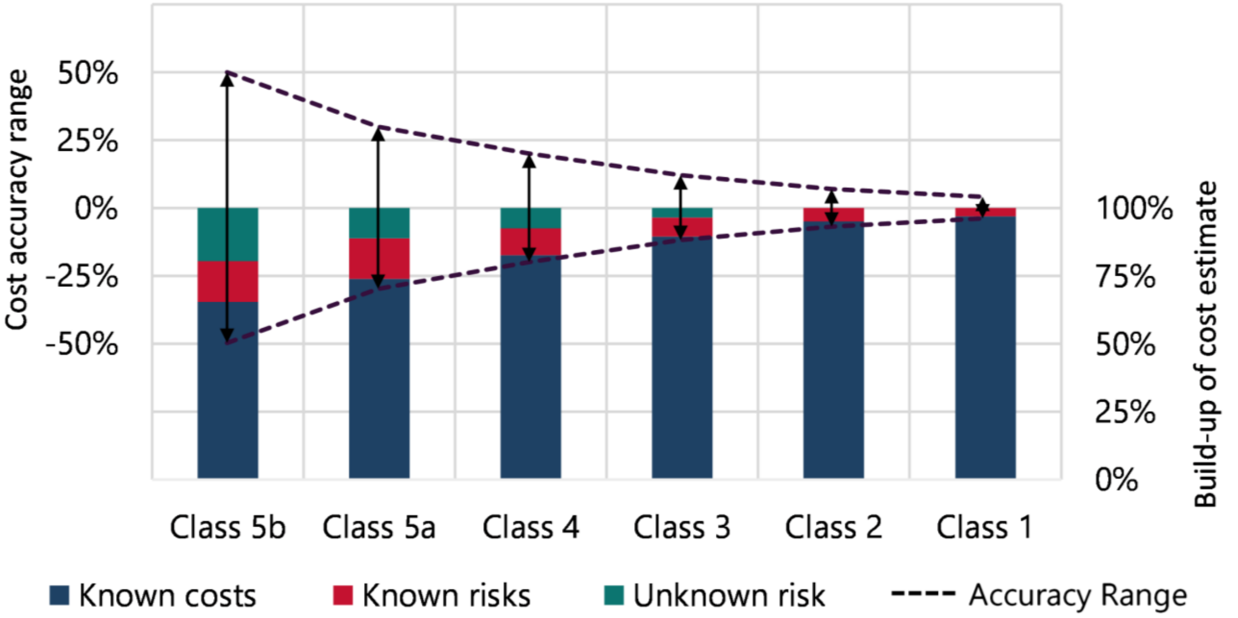
Indirect costs

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

3.2.2 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 building block costs are shown as "known costs". Known risk allowances and unknown risk allowances 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.

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



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 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. 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 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.

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, 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 3.1, in response to stakeholder feedback on the draft report, 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 6, with further explanation below.

Table 6 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	30%	±50%
Class 5a	Screening level scoping including high level site-specific review and TNSP input	15%	±30%

A. Unknown risk allowance defined as a percentage of the known cost (adjusted baseline cost).
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.

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.

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 average unknown risk allowance of 15%. This was determined by GHD using statistical analysis of current major projects as they progressed from screening stage scope definition to CPA – further detail on this analysis is provided in the GHD report[22]. 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.

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.

[22] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

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.

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. Full details of the Transmission Cost Database construction including cost and risk data sources are given in GHD's report[23].

3.2.3 Update of the AEMO Transmission Cost Database

AEMO's Transmission Cost Database was developed in 2021 and was first published alongside the 2021 Transmission Cost Report. The Transmission Cost Database is a tool which allows AEMO to develop cost estimates for future ISP network expansion 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.

In 2022, AEMO engaged an independent consultant Mott MacDonald to deliver a suite of updates to the Transmission Cost Database[24]. These updates improve the alignment of the Transmission Cost Database with TNSPs' best practice in conceptual cost estimates for transmission infrastructure and improve the accuracy of the tool through review of the attribute and risk factors. Significant TNSP engagement was necessary to update the Transmission Cost Database as many transmission projects have progressed through the RIT-T process since the original development of the database.

The updated Transmission Cost Database is available for download from AEMO's website[25]. The consultant's report on the Transmission Cost Database[26] update is also available for stakeholder comment as part of consultation on the *Draft 2023 Transmission Expansion Options Report.*

Consultation questions

1. Do you have any feedback on the update to the AEMO Transmission Cost Database? If yes, please provide data and evidence for any suggested enhancements.

3.3 Review of TNSP cost estimates

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.

[23] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[24] Refer to Attachment 1 – *Transmission Cost Database Update Final Report*. Mott MacDonald.

[25] Registration for the Transmission Cost Database tool is available at https://forms.office.com/r/YbmiGc24TP.

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

AEMO has adopted the AACE standard for the ISP. TNSPs each have a unique 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.
- Recent experience in procuring sites, land, and easement corridors.

3.3.1 Objectives

AEMO engaged 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 were as follows:

- 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.

3.3.2 Checklist development

AEMO 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.
- Class 3/2/1: 'For Construction' electrical and civil diagrams.

The 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.

3.3.3 Review and adjustment process

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

1. Classification and preliminary screening of cost estimates:
   a) TNSP provided completed checklist responses for each project option (ahead of providing cost estimate).
   b) AEMO approximated the class of the estimate for that project option. This was done by reviewing the set of TNSP responses against the AEMO checklist. The assigned class was that which had the highest correlation against the responses.

   c) AEMO reviewed the TNSP's allocation for unknown risks against the expectation for the assigned class (See Section 3.2.2).
   d) AEMO worked with the TNSP to resolve any missing cost components or differences in risk allocation treatments.
2. Review of cost estimates:
   a) TNSP provided cost estimate for each project option.
   b) AEMO estimated cost in parallel, using the Transmission Cost Database.
   c) AEMO compared estimates, and worked with the TNSP to resolve any significant differences in cost components or risk allowances.
3. Final alignment of cost estimates:
   a) AEMO carried out final review of TNSP updated estimate.
   b) Where sufficient information was not provided to AEMO, or where missing or insufficient allowance was made for cost components or risk, AEMO considered requirement for an additional allowance based on the Transmission Cost Database.

3.3.4 Review outcomes

AEMO will receive preparatory activities and actionable project cost estimates before the release of the final *Transmission Expansion Options Report* and will provide a review of outcomes in this section of the final report

3.4 Estimating operational expenditure

To estimate the operational expenditure for transmission projects, 1% of the total capital cost per annum is typically assumed as operation and maintenance cost for each transmission project, as this has historically been an appropriate figure for new build projects dominated by line works rather than substation works, and at present this value appears to be appropriate for future project estimates.

AEMO will apply a different value for projects where sufficient justification and evidence exists. For example, the development of the Strategic Benefit Payments Scheme[27] released by the New South Wales Government in October 2022 will mean that 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*"[28].

3.5 Economic, social and environmental costs and benefits

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

[27] At https://www.energyco.nsw.gov.au/community/strategic-benefit-payments-scheme.

[28] 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.

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, and 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 and dependent on obtaining planning and environmental approvals under relevant state and federal legislation.

The regulatory framework

The ISP is carried out in compliance with the National Electricity Rules (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[29] within 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, which includes matters like broader social and environmental impacts[30]. 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

[29] For further explanation of the cost estimation undertaken as part of the ISP process, please see the AER publication 'Cost Benefit Analysis Guidelines' section 3.3.3 (Valuing Costs), at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[30] The CBA Guidelines (pages 18 and 21) 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/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

necessary planning and environmental approvals. Broader social and environmental impacts are considered as part of the relevant jurisdictional environmental and planning assessment processes.

Overhead and underground options

The expansion 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, expansion 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 reliably served the community for many years. In some 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-stringing and direct drilling.
- Alternate technologies, including high-voltage alternating current (HVAC) and high-voltage direct current (HVDC).
- 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.

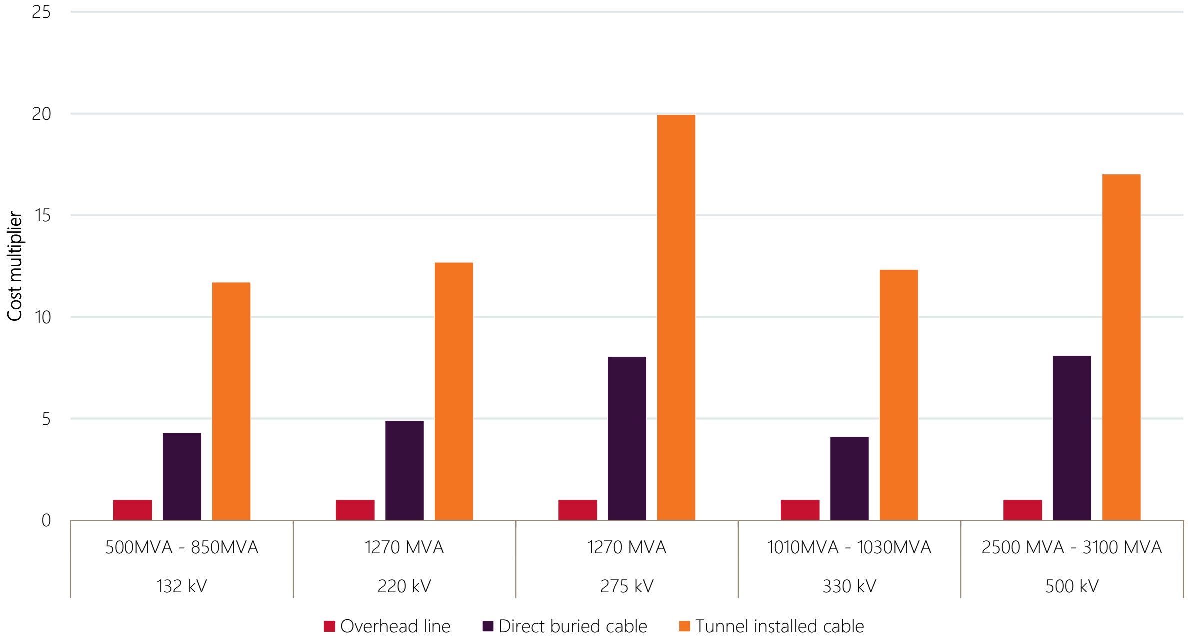
In the absence of detailed designs, AEMO has made the following assumptions for considering undergrounding in areas where overhead transmission lines are not expected to be technically feasible or are not compliant with planning requirements or environmental legislation:

- HVAC underground cable is suited to lengths below approximately 50 km. Beyond 50 km length, 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 7 shows a comparison of these cost estimates for given voltage levels and power transfer capacities. The HVAC option is included as a reference point. The costs of underground cables are approximately four to 20 times higher than overhead lines. Direct buried cables are at the lower end of this range, while tunnel-installed cables are at the upper end.

Figure 7 Indicative unit cost multiplier from HVAC overhead lines to HVAC underground cables



Notes:

- 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.

3.6 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[31] and the 2022 *Market Capacity of Electricity Infrastructure* report[32]. These reports studied the labour and material requirements to fulfil the NEM-wide generation and transmission projects included in the 2020 and 2022 ISPs.

The Transmission Cost Database allows the selection of a known risk to reflect the impact on transmission costs of the concurrent delivery of large transmission projects that is attributable to competition for labour and materials. However, this has not so far been applied to the majority of Class 5a/b projects in the ISP, because they are so far in the future (10-15 years) that detailed construction schedules cannot be forecast with accuracy. It is expected that the projects estimated by the TNSPs will have allowances included for market pressure, since these are to be constructed in a shorter time horizon.

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

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

3.7 Projected changes in infrastructure costs over time

The Transmission Cost Database update has been implemented during a challenging time for major infrastructure projects due to supply chain constraints and rising material costs. The objective of monetary policy globally and in Australia is to keep long-term inflation lower than current observed levels. The Transmission Cost Database is intended for estimating the cost of transmission infrastructure projects that will be delivered beyond two years after the publication of the 2024 ISP, and so it is crucial to include only long-term persistent cost increases.

The Transmission Cost Database provides cost estimates for June 2022 dollars, but project costs can be escalated to any year up to 2040. When the ISP market modelling is complete, project cost estimates can be escalated to the relevant year. The final 2023 *Transmission Expansion Options Report* will publish project cost estimates in June 2022 dollars.

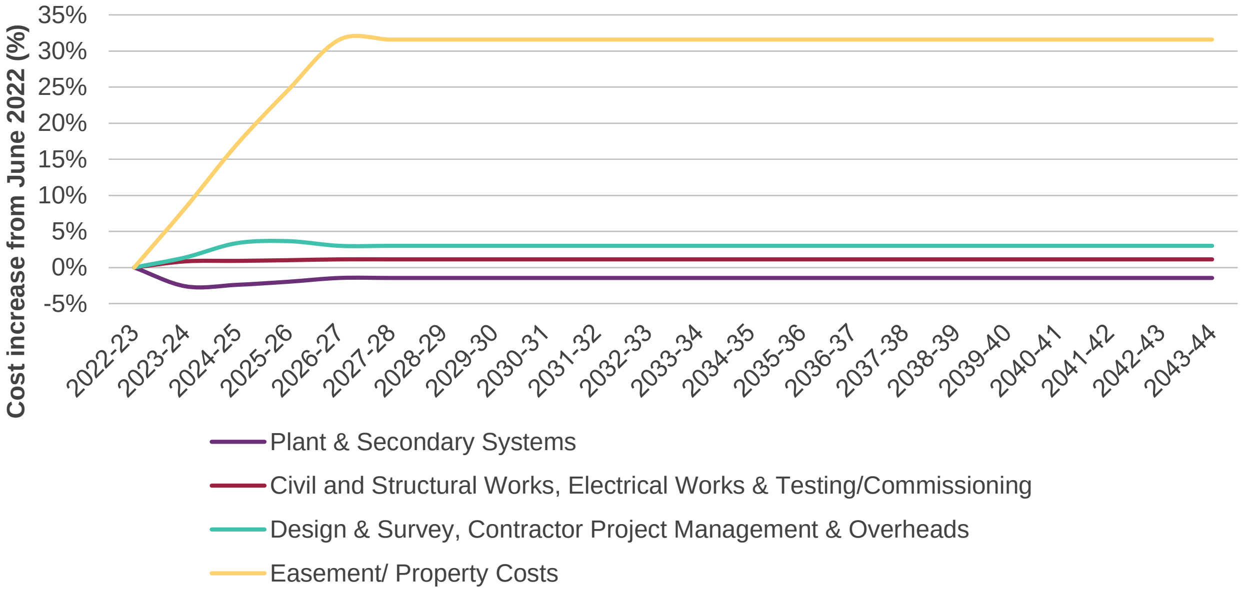
Mott MacDonald has provided a proposed approach for forecasting transmission costs over the long term in its report accompanying the update of the Transmission Cost Database[33].

Generation cost estimates for the ISP, provided through AEMO's collaboration with CSIRO and Aurecon, reflect a short-term increase in cost due to inflationary pressures prior to 2027. From 2027 onwards, costs driven by commodities and labour are expected to settle to a long-term trend.

AEMO proposes to assume that projected cost increases for transmission infrastructure also settle beyond 2027, to ensure a consistent approach for like parameters in the ISP. This cost forecast does not address the future cost of biodiversity offsets, as AEMO's position is to address this through operational expenditure given the nature of jurisdictional schemes.

Figure 8 illustrates the projected transmission infrastructure costs using a basket of indices approach.

Figure 8 Projected cost increases for transmission infrastructure



33 At https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

For the ISP, transmission augmentation project costs will be updated to reflect expansion option timing in the Draft ISP and will be in real June 2022 dollars. Mott MacDonald's proposed forecasting approach identifies a clear cost peak in June 2022, from which Plant and Secondary System costs decline in 2023 before leveling out in 2027. Civil, structural, electrical works and testing see a slight increase from 2022 costs before leveling out from 2027. Easement and property costs are expected to continue to rise to 2027, and AEMO will apply an assumed long-term settlement trend beyond 2027.

Consultation questions

2. Do you have any feedback on the proposed approach to forecasting future transmission cost increases? If yes, please provide data and evidence for any suggested enhancements.

3.8 Transmission project lead time

The ISP ODP is strongly influenced by the lead times and expected in-service dates (EISDs) assumed for transmission projects. These projects may already be committed or anticipated projects[34] from TNSPs and other organisations, or they may be more speculative options which are less certain or progressed.

AEMO is currently consulting on how the ISP framework can better incorporate the uncertainty associated with transmission project lead time through a proposed update to the ISP Methodology[35]. AEMO is proposing that in addition to ongoing joint planning with TNSPs and jurisdictional bodies to understand potential project lead times, AEMO may also review and possibly extend project lead times to acknowledge and incorporate the greater uncertainty observed in delivery of these major infrastructure projects. This would also allow AEMO to quantify the delay risk caveats often noted by project proponents when lead time estimates are provided to AEMO.

In this Draft 2023 *Transmission Expansion Options Report*, AEMO has collaborated with TNSPs and jurisdictional bodies to understand project lead times for the augmentation options in this report. Subject to the outcomes of the ISP Methodology consultation, AEMO may review and amend project lead times for the final 2023 *Transmission Expansion Options Report*. This would be done in cases where AEMO considered it prudent to acknowledge and incorporate the greater uncertainty observed in the delivery of these major infrastructure projects.

In this Draft 2023 *Transmission Expansion Options Report*, AEMO has also re-defined the project lead time categories. A short lead time is now within 3-5 years (rather than 1-3 years for previous publications), a medium lead time is now within 6-7 years (rather than 4-5 for previous publications) and a long lead time is now beyond seven years (rather than five years and beyond for previous publications). This change has been made to acknowledge that regulatory and environmental approvals, as well as supply chain issues, mean that that delivery of a new transmission project less than three years after the release of an ISP is highly unlikely.

[34] 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.

[35] AEMO has a consultation page for updates to the ISP Methodology, at https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology. AEMO welcomes feedback in response to the proposed updates to the ISP Methodology.

3.9 Social licence for transmission projects

Securing local community acceptance, or 'social licence', will be vital to the timely delivery of new infrastructure projects in the NEM. The NEM is capable of delivering enough low-emissions electricity to support Australia's economic and environmental goals, but a clear social licence is required for the scale of investment needed.

AEMO has established an Advisory Council on Social Licence to assist in understanding social licence issues facing the energy transition including for consideration in development of the ISP[36].

AEMO has sought to incorporate social licence considerations in successive IASRs and ISPs through extensive consultation with governments, TNSPs, consumer advocates and other stakeholders[37].

TNSPs and jurisdictional bodies also incorporate social licence considerations in their project design and cost estimates for projects which are under development. In cases where TNSPs' and jurisdictional bodies' cost estimates include allowances to address social licence matters, these will be in AEMO's cost estimates for the 2024 ISP where consistent with the processes outlined in Section 3.3 of this 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. This includes ensuring the design of transmission assets take advantage of available design and technology choices to minimise their impact on land use.

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 is not responsible in its National Transmission Planner function for ultimate design, location or route selection or delivery of transmission projects in the NEM[38]. As any projects become more likely or certain, the relevant TNSP or jurisdictional body will consider any potential routes and locations in detail as well as engage with potentially affected communities, landowners and other stakeholders.

AEMO will incorporate feedback received on the Draft 2023 IASR and this Draft 2023 *Transmission Expansion Options Report* into the transmission augmentation options to be considered for the 2024 ISP. Consideration of social licence matters in the 2024 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,
- Selection of sensitivity analyses to consider the impact of variables relating to social licence on the ISP outcomes and to help inform selection of the ODP,

[36] Further information about the Advisory Council on Social Licence is available at https://aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/social-licence-advisory-council.

[37] For the most recent IASR consultation, see the Draft 2023 IASR at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Social licence matters are considered on pages 25, 118, 121 and 122 of the Draft 2023 IASR. For the most recent ISP, see https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Social licence is considered throughout the 2022 ISP, including a dedicated section in Appendix 3: Renewable Energy Zones.

[38] This statement applies to the ISP matters considered in this report as part of AEMO's role as the National Transmission Planner under the National Electricity Law. Separately, AEMO also has a unique role in Victoria, with responsibility for the planning of the Victorian transmission network. Further information about AEMO's role in Victoria is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning.

- Use of land use limits and resource limits in the ISP modelling, as consulted on through the Draft 2023 IASR process,
- 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[39],
- Selection of locations for potential REZs through consultation on successive IASRs and ISPs, and
- Potential application of any other appropriate methods to help inform selection of the ODP.

AEMO welcomes stakeholder feedback on social licence considerations for the ISP transmission augmentation project selection process in general, as well as any specific feedback on the flow path, REZ and group constraint information and options provided in this report.

Consultation questions

3. Do you have any suggested alternatives to AEMO's approach to considering social licence for transmission projects for the ISP? If yes, what are the alternatives? Please provide information or evidence supporting the use of any alternative approach.
4. Do you have any specific feedback on social licence considerations for the flow paths, REZs or group constraints considered in this report? If yes, please provide information or evidence to support the feedback, where possible.

[39] This matter is also under consideration through consultation on updates to the ISP Methodology, at https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

4 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. 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, or have preparatory activities being developed. Where available, transfer limits and cost estimates of these augmentation options were sourced from the relevant TNSPs and jurisdictional bodies.

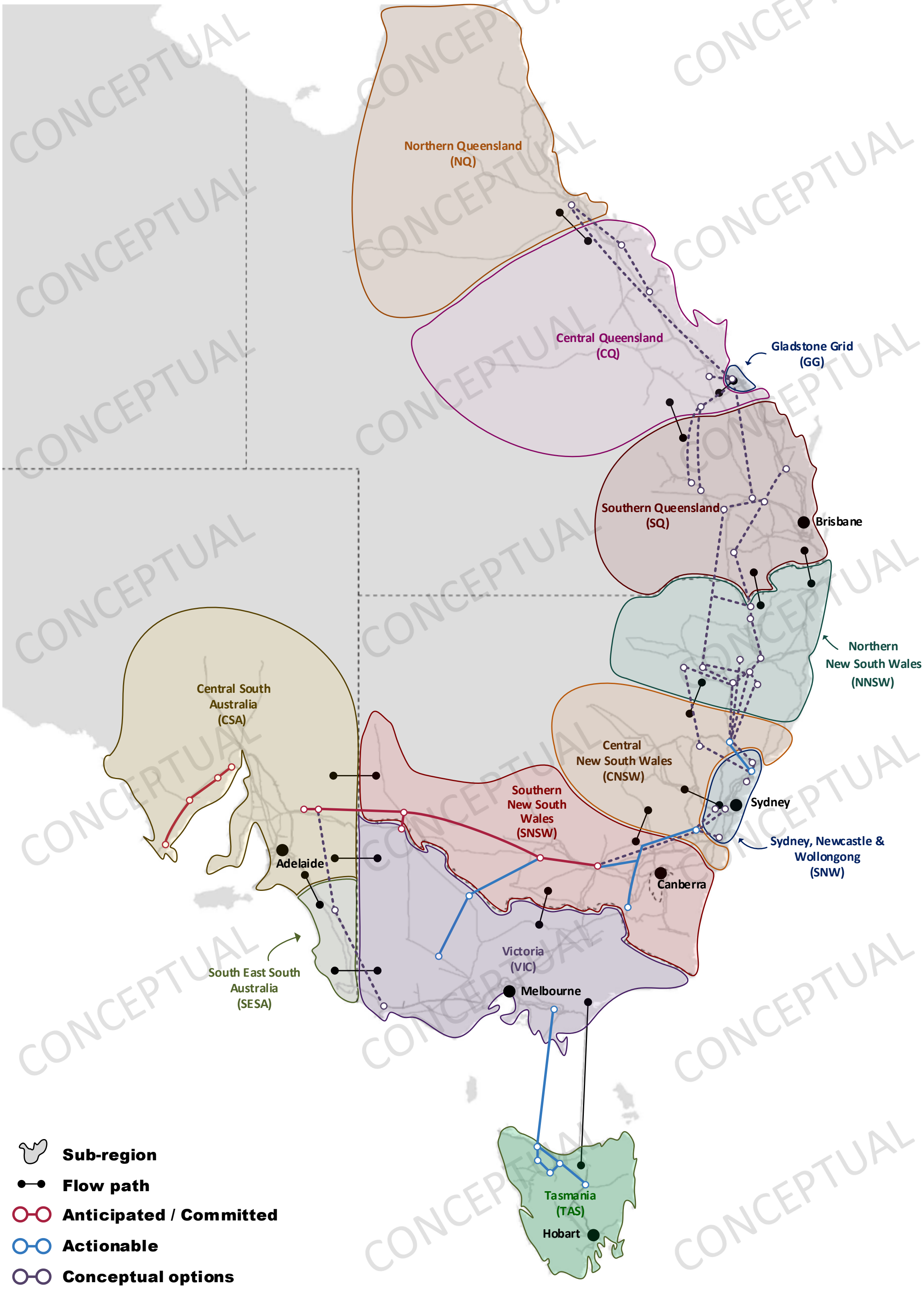
This section provides the following information:

- A legend and explanation of tables (Section 4.1).
- Central Queensland to North Queensland (Section 4.2).
- Central Queensland to Gladstone Grid (Section 4.3).
- Southern Queensland to Central Queensland (Section 4.4).
- Northern New South Wales to Southern Queensland (Section 4.5).
- Central New South Wales to Northern New South Wales (Section 4.6).
- Central New South Wales to Sydney, Newcastle and Wollongong (Section 4.7).
- Southern New South Wales to Central New South Wales (Section 4.8).
- Victoria to Southern New South Wales (Section 4.9).
- Tasmania to Victoria (Section 4.10).
- Victoria to South East South Australia (Section 4.11).
- South East South Australia to Central South Australia (Section 4.12).

Consultation questions

5. Do you have any feedback on the flow path augmentation options provided in this report, including their conceptual design, lead time, location and cost estimates? Please provide evidence to support your feedback.

Figure 9 Map of flow path options for Draft 2023 *Transmission Expansion Options Report*



4.1 Legend and explanation of tables

The tables in Section 4 and Section 5 provide an overview of the characteristics of each network development option. The following template explains the criteria and terminology used in the tables.

Summary	
A brief description of the existing network is provided (for example, network capacity, projects to increase capacity, findings from the 2022 ISP).	
Existing network capability	
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. The capacity is sourced from recent historical data. 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. 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.	
Augmentation options – these include the conceptual design, capability, cost and timing for flow path augmentation options	
Additional network capacity (MW)	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. For REZs, the power flow is always in one direction from the REZ to the network.
Cost	The costs are based on 2022 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. 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, 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 2023 IASR Workbook.
Cost classification	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 3.1.
Lead time	Lead times represent the likely minimum time for service from the date of publication of the final 2024 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).
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.	
Adjustment factors: • Location (urban, regional and remote). • Greenfield/brownfield (greenfield, brownfield and partly brownfield) – greenfield is chosen unless otherwise specified. • Land use (desert, scrub, grazing and developed area). • Terrain (flat/farmland, mountainous and hilly/undulating). • Jurisdiction (state and Rural Bank defined sub-region[40]). • 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.	

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

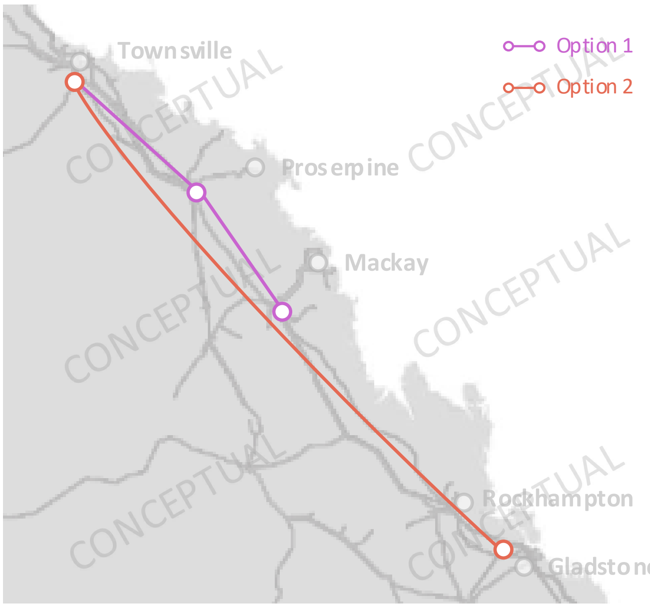
Known risk: where the risks are identified but ultimate value is not known. There are nine known risk factors: • Compulsory acquisition (BAU, low and high). • Cultural heritage (BAU, low and high). • Environmental offset risks (BAU, low, high, very high, and observed maximum). • Geotechnical findings (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).

4.2 Central Queensland to North Queensland

Summary

To improve the modelling of network losses, the Central-Northern sub-region from the 2022 ISP was further divided into North Queensland (NQ) and Central Queensland (CQ) sub-regions. Upgrade options associated with this new flow path may be built when generation in REZs Q1 to Q5 (Northern Queensland) exceeds 2,500 MW. These augmentations facilitate transmission of generation in northern Queensland to load centres further south.

In previous ISPs, only a single option was proposed to increase the maximum network transfer capability between CQ and NQ. However, an additional option is now suggested which would permit the connection of a proposed Pioneer-Burdekin pumped hydro storage project (of up to 5,000 MW capacity) in North Queensland consistent with the Queensland Government's announcement for the SuperGrid under the Queensland Energy and Jobs Plan (QEJP).



Existing network capability

The current network was designed to facilitate the transmission of power from Central Queensland to support the load in Northern Queensland. As a result, the Central and North Queensland sub-regions can only support up to 2,500 MW of generation across the five 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. The maximum transfer capability is limited by thermal ratings and voltage stability for the loss of CQ or NQ transmission network elements.

From NQ to CQ maximum transfer capability is 1,200 MW at peak demand and summer typical levels and 1,400 MW at winter reference periods.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Construct an additional 275 kV double-circuit line from Ross to Strathmore to Nebo, initially switching one side only.	1,100 (both directions of CQ to NQ) REZ Q3: 1,100	1,105	Class 5b (±50%)	Medium
Option 2: • Establish 500 kV substations at locality of Townsville (NQ) and locality of northern part of CQ. • 2 x 1,500 MVA 500 / 275 kV Transformers at new NQ substation (if CopperString build precedes the CQ-NQ option, these transformers will be limited to ~900 MVA due to energisation issues). • 2 x 1,500 MVA 500 / 275 kV transformers at northern CQ substation • Establish 1x500 kV double-circuit steel tower (DCST) line from CQ to northern CQ substation • Establish 1x500 kV DCST line from northern CQ to NQ substation • Special protection scheme for transfer limit increase(similar to Virtual transmission line). Cost of this Network Service Agreement (NSA) excluded. *Prerequisite: CQ-SQ Option 5 (QEJP)*	3,000 (both directions of CQ to NQ) REZ Q3: 3,000	3,488	Class 5b (±50%)	Long

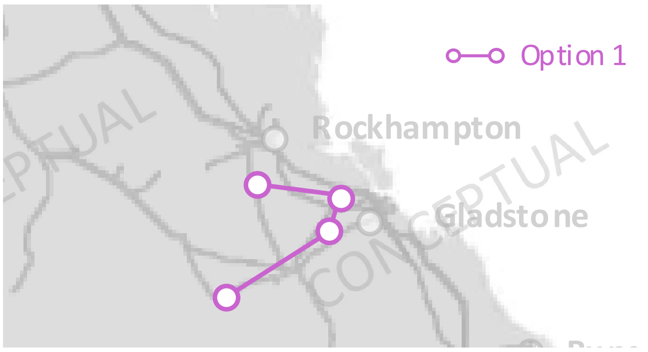
Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Scrub • Project network element size: Above 200km, 6-10 bays • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: • Compulsory acquisition: Low • Cultural heritage: Low • Market activity: Tight • Others: BAU • Unknown risks: Class 5b
Option 2	As per Option 1	As per Option 1

4.3 Central Queensland to Gladstone Grid

Summary

Following the retirement or reduced generation from Gladstone Power Station and increased generation in North Queensland, the transmission network supplying the Gladstone area will be constrained. This will restrict supply to forecast demand at Boyne Island, Calliope River, Larcom Creek and Raglan substations. 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.

AEMO has previously recommended Powerlink complete preparatory activities in the 2022 ISP for reinforcement of Central and North Queensland (CNQ) and Gladstone Grid (GG) section.



Existing network capability

The maximum power transfer capability is influenced by the amount of generation dispatched within northern and central Queensland, particularly at Gladstone. This transfer capability is influenced by the thermal capacity of the Calvale–Wurdong, Bouldercombe–Calliope River, Bouldercombe–Raglan, 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 conditions.
- 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)	Cost classification	Lead time
Option 1: • New 275 kV high-capacity double-circuit line between Calvale and Calliope River. • Rebuild Calliope River to Larcom Creek 275 kV high-capacity double-circuit line. • Rebuild Larcom Creek to Bouldercombe 275 kV high-capacity double-circuit line with one line tapped at Raglan. • A new (third) 275/132 kV transformer at Calliope River.	2,600 (CQ to GG) 500 (GG to CQ)	This cost estimate is still subject to joint planning consultation with Powerlink.	To be confirmed, subject to joint planning consultation with Powerlink.	Short

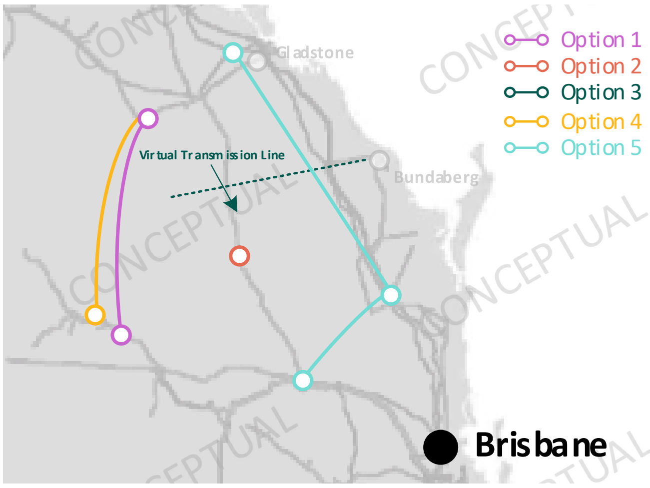
Adjustment factors and risk: N/A (Preparatory activity)

4.4 Southern Queensland to Central Queensland

Summary

The maximum transfer capability from Central and Northern Queensland (CNQ) to Southern Queensland (SQ) is currently limited to approximately 2,100 MW. As new generation connects in CNQ, congestion along this corridor will increase and generation will be curtailed.

In previous ISPs, four options were proposed to increase the maximum network transfer capability between CQ and SQ. However, with the QEJP, a new Option 5 is added.



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. It is assumed Powerlink establishing new substation at Karana Downs for teeing both Blackwall – Rocklea 275 kV lines to South Pine. From SQ to CQ maximum transfer capability is 1,100 MW at peak demand, summer typical levels and at winter reference periods. 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)	Cost classification	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 – Wandoan South 275 kV circuits.	900 (both directions of SQ to CQ). REZ Q6: 900	476 (2020 $). Sourced from Powerlink Preparatory activity[41]	Class 5	Medium
Option 2: • Mid-point switching substation on the existing Calvale–Halys 275 kV double-circuit line.	0 (SQ to CQ) 300 (CQ to SQ)	69	Class 5b (±50%)	Short
Option 3: • Non-network option – a Virtual Transmission Line option with a 300 MW energy storage system in north of Calvale and South of Halys.	300 (both directions of SQ to CQ)	Non-network augmentation		
Option 4: • A 1,500 MW HVDC bi-pole overhead transmission line from Calvale to South West Queensland. • A new 1,500 HVDC bipole converter station in locality of Calvale. • A new 1,500 HVDC bipole converter station in South West Queensland. • AC network connection between HVDC converter station and 275 kV substation in Calvale. • AC network connection between HVDC converter station and 275 kV ac network in South West Queensland.	1,500 (both directions of SQ to CQ) REZ Q6: 1,500	1,751	Class 5b (±50%)	Long

[41] Powerlink Queensland. June 2021. *Preparatory Activities – CQSQ Transmission Link*. At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/preparatory-activities-cqsq-transmission-link.pdf?la=en.

Option 5: • Establish 500 kV Halys substation (with 3x500/275 kV 1,500 MVA transformers). • Establish 500 kV substations at locality of Gladstone (CQ substation) and Woolooga West (each with 2x500/275 kV 1,500 MVA transformers). • Establish CQ 275 kV substation. • New dynamic reactive support at CQ substation. • A new 1x500 kV double-circuit line between Halys and Woolooga West. • A new 1x500 kV double-circuit line from Woolooga West to CQ substation. • A new 1x275 kV double-circuit line from Woolooga West to existing Woolooga. • Cut in CQ substation 275 kV to Calliope River to Calvale circuits • 2x 275 kV phase shifting transformers at existing Woolooga substation on existing 275 kV eastern corridor. • Special protection scheme for transfer limit increase (similar to Virtual transmission line). Cost of this NSA excluded. *Prerequisite: CNQ-GG Option 1 (GGR)*	3,150 (both directions of SQ to CQ) Q1-Q6 path: 3,000 (should there be no transmission constraints further north)	1,893	Class 5b (±50%)	Medium

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: • Proportion of environmentally sensitive areas: • Location (regional/distance factors): • Delivery Timetable:	• Known risks: • Unknown risks:
Option 2	• Land use: Scrub • Greenfield • Jurisdiction: QLD – South • Project network element size: 1-5 Bays • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Optimum	• Known risks: BAU except for outage restrictions: High. • Unknown risks: Class 5b
Option 4	• Land use: Scrub • Greenfield • Jurisdiction: QLD – South and QLD - Central • Project network element size: Over 200km, 6-10 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: • Project complexity: Partly complex • Others: BAU • Unknown risks: Class 5b
Option 5	• Land use: Scrub • Partly Brownfield • Jurisdiction: QLD – South and QLD - Central • Project network element size: Over 200km, 1-5 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: • Project complexity: Partly complex • Market activity: Tight • Outage restrictions: High • Others: BAU • Unknown risks: Class 5b

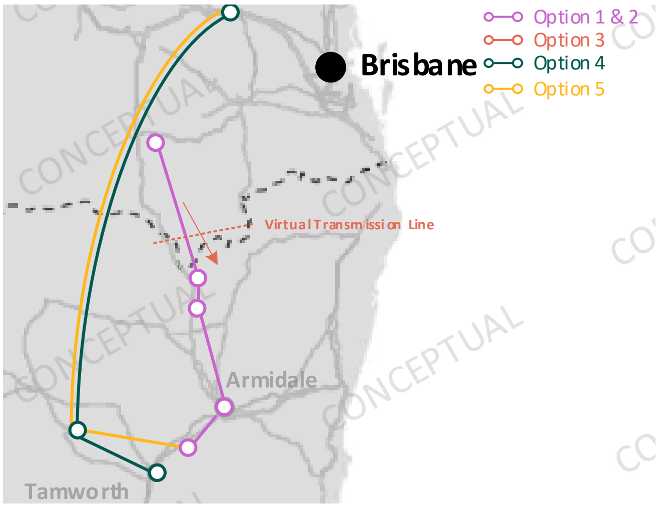
4.5 Northern New South Wales to Southern Queensland

Summary

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

The QNI minor project which increases the transfer capacity of the existing QNI has been commissioned and inter-network testing considered complete from June 2023.

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. In the 2022 ISP, AEMO required that Powerlink and Transgrid complete preparatory activities for QNI Connect 500 kV option, and that Transgrid complete preparatory activities for a QNI Connect 330 kV Option.



Existing network capability

NNSW to SQ expected transfer capability is 685 MW at peak demand and 745 MW at summer typical and winter reference periods. The maximum transfer capability is limited by voltage or transient stability for loss of the Kogan Creek generator.

In the reverse direction, SQ to NNSW expected transfer capability is 1,205 MW, 1,165 MW and 1,170 MW at peak, summer typical and winter reference periods respectively. The transfer capability is limited by thermal capacity of 330 kV lines between Bulli Creek and Armidale or Armidale and Tamworth following a credible contingency.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • A new 330 kV single-circuit line from locality of New England Hub 5 to Dumaresq to Bulli Creek to Braemar. • A new 330/275 kV transformer at Braemar. • Cut-in Armidale-Dumaresq 330 kV line (8C) at Sapphire. • 330 kV Line shunt reactor at New England Hub 5, Dumaresq, Bulli Creek, and Braemar for the New England Hub 5 – Dumaresq - Bulli Creek - Braemar 330 kV circuits. (Pre-requisite: Cut-in both Tamworth-Armidale 330 kV lines to a new substation in locality of New England Hub 5).	910 (NNSW to SQ) 1,080 (SQ to NNSW)	1,537	Class 5b (±50%)	Medium
Option 2: • A new 330 kV double-circuit line from locality of New England Hub 5 to Dumaresq to Bulli Creek to Braemar. • A new 330/275 kV transformer at Braemar. • Cut-in Armidale-Dumaresq 330 kV line (8C) at Sapphire. • 330 kV Line shunt reactors at New England Hub 5, Dumaresq, Bulli Creek, and Braemar, for the 330 kV lines between New England Hub 5 and Braemar (via Dumaresq and Bulli Creek). • (Pre-requisite: Cut-in both Tamworth-Armidale 330 kV lines to a new substation in locality of New England Hub 5).	1,400 (NNSW to SQ) 2,300 (SQ to NNSW)	1,817	Class 5b (±50%)	Medium
Option 3: • A Virtual Transmission Line option with a 300 MW energy storage system south of Armidale and north of Braemar.	300 (in both directions of NNSW to SQ)	-		

Option 4: • A 2,000 MW HVDC bi-pole overhead transmission between a new substation in North West New South Wales (NWNSW) REZ 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 NWNSW REZ and Tamworth.	1,800 (NNSW to SQ) 2,000 (SQ to NNSW)	3860	Class 5b (±50%)	Long
Option 5: • Establish a new substation in NNSW and to New England REZ Hub 5. • A new 500/275 kV transformer at Halys substation • A new 1x500 kV double-circuit line between Halys and a new substation in NNSW. • A new 1x500 kV double-circuit line between a new substation in NNSW and New England REZ Hub 5). • 2x 330 kV phase shifting transformers on parallel path (existing QNI 330 kV lines). *Pre-requisite: CQ-SQ Option 5 (QEJP), CNSW-NNSW Option 1.*	3,000 (in both directions of NNSW to SQ	2,861	Class 5b (±50%)	Long

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Partly Brownfield • Jurisdiction: QLD – South and NSW • Project network element size: Over 200km, 1-5 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: • Environmental offset risks – High • Compulsory acquisition – High • Market Activity – Tight • Others: BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Partly Brownfield • Jurisdiction: QLD – South and NSW • Project network element size: Over 200km, 1-5 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Long	• As per option 1
Option 4	• Land use: Grazing • Greenfield • Jurisdiction: QLD – South and NSW • Project network element size: Over 200km, 1-5 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: • Project complexity: Partly complex • Market activity: Tight • Others: BAU • Unknown risks: Class 5b
Option 5	• Land use: Grazing • Greenfield	• Known risks: • Project complexity: Partly complex

	• Jurisdiction: QLD – South and NSW • Project network element size: Over 200 km, 6-10 bays per substation • Proportion of environmentally sensitive areas: 50 percent • Location (regional/distance factors): Regional • Delivery Timetable: Tight	• Market activity: Tight • Others: BAU • Unknown risks: Class 5b

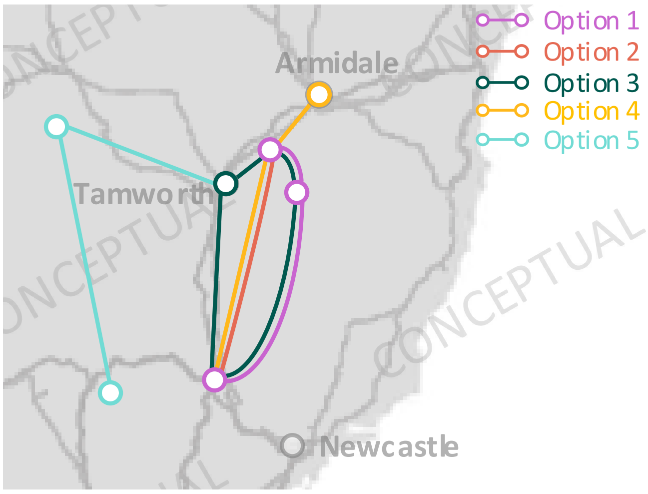
4.6 Central New South Wales to Northern New South Wales

Summary

The Central New South Wales (CNSW) to Northern New South Wales (NNSW) corridor represents a portion of the network which forms part of 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 QNI minor project which increases the transfer capacity of the existing QNI has been commissioned and considered in service from June 2023. This means it's included in the capacity calculations below. In the 2022 ISP, AEMO recommended that Powerlink and Transgrid complete preparatory activities for QNI Connect 500 kV option and additionally Transgrid to complete NSW scope of QNI Connect 330 kV Option.

In the 2022 ISP, major augmentation of CNSW-NNSW flow path was identified as an actionable New South Wales project (New England REZ Transmission Link) as defined in the New South Wales Electricity Strategy.



Existing network capability

- 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.
- 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.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New Central South (Hub 1) 500/330 kV substation in New England with 3 x 500/330/33 kV 1,500 MVA transformers. • New 330 kV Central (Hub5) switching station in New England and cut into the existing lines between Tamworth and Armidale. • New 500 kV built and initially 330 kV operated double-circuit line from Hub 5 to Hub 1 • New 500 kV double-circuit line between Hub 1 and Bayswater with Quad Orange conductor. • 4 x 500 kV 150 MVAr line shunt reactors (in total) are required for 500 kV double-circuit line between Hub 1 and Bayswater. • New 6 x 330 kV 200 MVA phase shifting transformers at Hub 5.	3,000 (both directions of CNSW to NNSW) REZ N2: 2,000	1,755	Class 5b (± 50%)	Medium
Option 2: • Expand Hub 5 switching station to 500/330 kV substation with 3 x 500/330/33 kV 1,500 MVA transformers. • Operate line between Hub 5 and Hub 1 from 330 kV to 500 kV. • New 500 kV double-circuit from Hub 5 to Bayswater with Quad Orange conductor. • 4 x 500 kV 150 MVAr line shunt reactors (in total) are required for 500 kV double-circuit line between Hub 5 and Bayswater. *Pre-requisite:, CNSW-NNSW Option 1.*	3,000 (both directions of CNSW to NNSW) (assuming downstream limitations addressed by Hunter Transmission Project/CNSW-SNW Option 1). REZ N2: 3,000	1,487	Class 5b (± 50%)	Long

Option 3: • New Central South (Hub 1) 500/330 kV substation in New England with 3 x 500/330/33 kV 1,500 MVA transformers. • New 330 kV Central (Hub5) switching station in New England and cut into the existing lines between Tamworth and Armidale. • New 500 kV built and initially 330 kV operated double-circuit line from Hub 5 to Hub 1 • New 500 kV double-circuit line between Hub 1 and Bayswater with Quad Orange conductor. • 4 x 500 kV 150 MVAr line shunt reactors (in total) are required for 500 kV double-circuit line between Hub 1 and Bayswater. • Rebuild portion of Line 86 from Hub 5 to Tamworth as 330 kV double-circuit line. • Rebuild Line 88 Tamworth - Muswellbrook and Line 83 Liddell - Muswellbrook as 330 kV double-circuit line. • Augment Hub 5, Tamworth, Muswellbrook and Liddell to accommodate additional lines.	3,600 (both directions of CNSW to NNSW) REZ N1+N2: 3,600	2,433	Class 5b (± 50%)	Long
Option 4: • 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.	1,750 (CNSW to NNSW) 2,000 (NNSW to CNSW) REZ N2: 2,000 MW	2,455	Class 5b (± 50%)	Long
Option 5: • A 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.	1,750 (CNSW to NNSW) 2,000 (NNSW to CNSW) REZ N1: 2,000 MW	2,640	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: Above 200km, no. of bays total 16 - 20 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b
Option 2	As per Option 1 above	As per Option 1 above
Option 3	• Land use: Grazing • Project network element size: Above 200km, no. of bays total 11 - 15 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU
Option 4	• Land use: Grazing • Project network element size: Above 200km, no. of bays above 31 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - High
Option 5	As per Option 4 above	As per Option 4 above

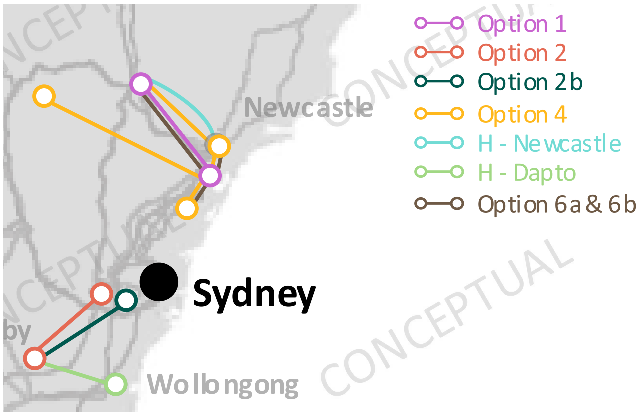
4.7 Central New South Wales to Sydney, Newcastle and Wollongong

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. Additional transmission network augmentation may be needed to supply the load centre.

The Waratah Super Battery (WSB) project is a priority transmission project in NSW[42]. WSB with a System Integrity Protection Scheme (SIPS) is proposed to increase transfer capacity from CNSW to SNW. This project also includes minor network augmentation to increase thermal capacity of Bannaby-Sydney West, Yass-Marulan and Yass-Collector-Marulan 330 kV lines.

In the 2022 ISP, the Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply) or the Hunter Transmission Project was identified as an Actionable ISP Project.



Existing network capability

The existing transfer capability varies depending on load and generation distribution within Sydney, Newcastle, and Wollongong areas, as well as the generation pattern from northern and southern NSW sub-regions.

For the existing network, transfer capability from the north and the south are separately identified to better define these limitations.

CNSW-SNW North flow path:

(sum of CNSW-SNW flow paths less CNSW-SNW South flow paths, see below)

The maximum transfer capability of the northern side of CNSW-SNW flow path is 4,490 MW at peak demand and summer typical, and 4730 at winter reference periods.

Maximum transfer capability is limited by several 330 kV lines and the most limiting elements are Liddell-Newcastle and Liddell-Tomago 330 kV lines.

It is assumed Vales Point generation is at maximum output and Eraring generation at zero output in these transfer limit calculations. 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:

(sum of flows on Bannaby – Sydney West, Marulan – Dapto, Marulan – Avon and Kangaroo Valley – Dapto 330 kV lines)

The maximum transfer capability from the southern side of CNSW-SNW flow path is 2,540 MW at peak demand and summer typical, and 2,720 at winter reference periods.

Maximum transfer capability is limited by several 330 kV lines and the most limiting element is Bannaby-Sydney West 330 kV line.

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 WSB project (including battery, SIPS, minor network augmentations, paired generation) is expected to increase the transfer capability by 660 MW and 250 MW for CNSW-SNW North and South, respectively.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 SNW Northern 500 kV loop or the Hunter Transmission Project (HTP): • Expand existing Eraring 500 kV substation. • A new 500 kV double-circuit line between Eraring and Bayswater substation. • Line reactors on 500 kV transmission lines between Eraring and Bayswater. • Two new 500/330 kV 1,500 MVA transformers at Eraring substation.	5,000 (This capacity increase is for accommodation of additional new generation from North of Bayswater and 2/3 generation from Central West NSW)	864	Class 5b (± 50%)	Medium

42 NSW Government, October 2022, "Government Gazette". At https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2022_2022-473.pdf.

	REZ N10: 2,000			
Option 2 SNW Southern Loop: • Establish a new substation in the locality of South Creek with 2 x 500/330/33 kV, 1500 MVA transformers. • Connect the new substation in the locality of South Creek into Eraring – Kemps Creek 500 kV lines and Bayswater – Sydney West and Regentville – Sydney West 330 kV lines. • A new 500 kV double-circuit lines from Bannaby to the new substation in the locality of South Creek. • Rebuild the section of existing Bannaby – Sydney West 330 kV line from locality of South Creek to Sydney West to double-circuit line. • Augment the existing Bannaby and Sydney West substations. • Line reactors on 500 kV transmission lines between Bannaby and locality of South Creek.	4,500 (This capacity increase is for accommodation of additional new generation south of Bannaby and 1/3 generation from Central West NSW). REZ N11:2,000	1,450 to 2,780 (2021 dollars)[43]	Class 5b (± 50%)	Medium
Option 2b: • Rebuild line 39 from Bannaby to Sydney West as double-circuit line. • Augment the existing Bannaby and Sydney West substations.	1,200 CNSW-SNW (This capacity increase is for accommodation of additional new generation from south of Bannaby)	525	Class 5b (± 50%)	Medium
Option 3 Both SNW Northern 500 kV loop and SNW Southern 500 kV loop: • CNSW-SNW Option 1. • CNSW-SNW Option 2.	8,600[44,45] (This capacity increase of 8,600 MW consists of maximum generation of 5,000 MW from NNSW and 4,500 MW from SSNW)	1,967	Class 5b (± 50%)	Long
Option 4: • A new 500 kV substation near Eraring. • A new 500 kV double-circuit line between substation near Eraring and Eraring. • A new 500 kV double-circuit line between Wollar South and new Eraring substation. • Two 500/330 kV 1,500 MVA transformers at Kemps Creek. • 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 Line 24 Vales Pt – Eraring and 92 Newcastle – Vales Point. • 1 x 330 kV single-circuit line between Liddell – Newcastle. • 1 x 330 kV single-circuit line between Eraring – Newcastle.	4,400[46] REZ N10:2,000 (This capacity increase is for accommodation of additional new generation from Central West NSW)	2,380	Class 5b (± 50%)	Long

[43] Consistent with the 2020 ISP, Transgrid has provided preparatory activities for this option. This includes cost estimates for this option. AEMO has published Transgrid's report, ISP Preparatory Activities – Reinforcing Sydney, Newcastle and Wollongong Supply (Southern Circuit. This report is available via https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[44] Transfer limit for CNSW-SNW Option 3 in 2022 ISP was 5,600 MW. This has been revised with increased load in SNW. Consistent load assumptions applied for all 500 kV augmentation options following HTP. Applicable for options 3, 4, 6a and 6b.

[45] AEMO is working closely with EnergyCo and Transgrid to further refine this limit for the final 2023 IASR. It is possible, but not confirmed, that a higher transfer limit will be included for the final 2023 IASR.

[46] AEMO is working closely with EnergyCo and Transgrid to further refine this limit for the final 2023 IASR.

• Line reactors on 500 kV transmission lines. *Pre-requisite: CNSW-SNW Option 1, N3 REZ Option 1.*				
H-Newcastle To provide access to port new 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.	5,000 (This is not an alternative option to supply SNW) This augmentation allows expansion of REZ N10.	1,612	Class 5b (± 50%)	Long
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.	5,000 (This is not an alternative option to supply SNW) This augmentation allows expansion of REZ N10.	1,382	Class 5b (± 50%)	Long
CNSW-SNW 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 Line 24 Vales Pt – Eraring and 92 Newcastle – Vales Point • 1 x 330 kV SCST line between Liddell – Newcastle • 1 x 330 kV SCST line between Eraring – Newcastle *Pre-requisite: CNSW-SNW Option 1.*	4,400[47] (This capacity increase is for accommodation of additional new generation from NNSW and CNSW)	1,765	Class 5b (± 50%)	Long
CNSW-SNW Option 6b: • A new 500 kV substation near Eraring substation. • A new 500 kV double-circuit line between substation near 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 Line 81 and 82. • Two 500/330 kV 1,500 MVA transformers at new substation 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 Line 24 Vales Pt – Eraring and 92 Newcastle – Vales Point. • 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.*	4,400[48] (This capacity increase is for accommodation of additional new generation from NNSW and CNSW)	1,365	Class 5b (± 50%)	Long
Adjustment factors and risk				

[47] AEMO is working closely with EnergyCo and Transgrid to further refine this limit for the final 2023 IASR.

[48] AEMO is working closely with EnergyCo and Transgrid to further refine this limit for the final 2023 IASR.

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Developed area • Project network element size: 100 to 200km, no. of total bays 1 – 5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - High • Unknown risks: Class 5b (± 50%)
Option 2	• Land use: Developed area • Project network element size: 100 to 200km, no. of total bays 6 – 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	As per Option 1 above
Option 2b	• Land use: Developed area • Project network element size: 100 to 200km, no. of total bays 6 – 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional / Urban • Delivery Timetable: Long	• Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - High
Option 3	• Land use: Developed area • Project network element size: Above 200km , no. of total bays 6 - 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional / Urban • Delivery Timetable: Long	As per Option 1 above
Option 4	As per Option 3 above	As per Option 1 above
H-Newcastle	• Land use: Scrub / Developed Area • Project network element size: Above 200 km, no. of total bays 16 - 20 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - High • Unknown risks: Class 5b
H-Dapto	• Land use: Scrub / Developed Area • Project network element size: 100 to 200km, no. of total bays 16 - 20 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	As per Option H-Newcastle above
Option 6a	As per Option 3 above except; Project network element size: 100 to 200km	As per Option 1 above
Option 6b	As per Option 3 above except; Project network element size: 100 to 200km	As per Option 1 above

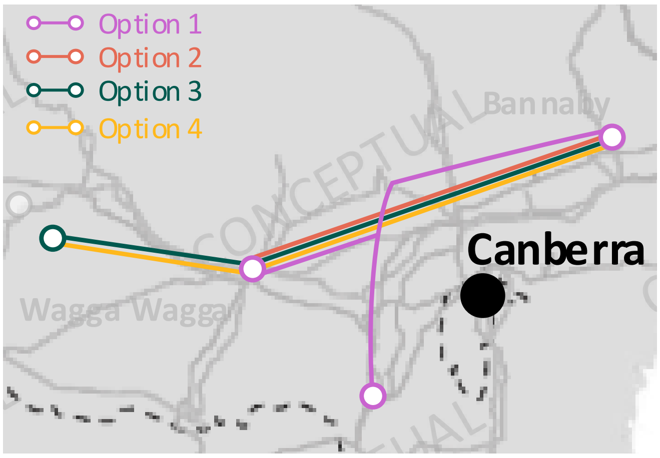
4.8 Southern New South Wales to Central New South Wales

Summary

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 is a proposed transmission network augmentation that reinforces the New South Wales southern shared network to increase transfer capacity to New South Wales load centres. This was identified as an actionable ISP project in the 2022 ISP. Transgrid has completed the RIT-T process for this project and early works funding has been approved by the AER.

Subsequent to HumeLink, three options are proposed to increase the maximum network transfer capability between SNSW and CNSW to access increased import from Victoria and South Australia with increased generation in SNSW to NSW major load centres.



Existing network capability

The maximum transfer capability from SNSW to CNSW is 2,700 MW at peak demand and summer typical and 2,950 winter reference periods. The maximum transfer capability is limited by thermal capacity of Yass– Marulan or Crookwell-Bannaby 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[49] or Gullen Range–Bannaby 330 kV lines following a credible contingency

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 (HumeLink): • New Wagga Wagga 500/330 kV substation and 330 kV double-circuit connection to the existing Wagga Wagga 330 kV substation. • Three new 500 kV transmission lines: - Between Maragle and Bannaby 500 kV substations. - Between Maragle and new Wagga Wagga 500 kV substations. - Between new Wagga Wagga and Bannaby 500 kV substations. • Three 500/330 kV 1,500 MVA transformers at Maragle. • Two 500/330 kV 1,500 MVA transformers at new Wagga Wagga. • 500 kV Line shunt reactors at the ends of Maragle – Bannaby, Maragle – new Wagga Wagga and new Wagga Wagga – Bannaby 500 kV lines.	2,200[50] N6+N7: 2,200 (N6: 1,500), N5: 800	3,317[51] (June 2020 dollars)	Class 4	Short
Option 2:	2,000 (both directions	2,322	Class 5b (± 50%)	Long

[49] Uprating of Marulan – Yass and Marulan – Collector – Yass 330 kV transmission lines were included in limit assessment.

[50] Limit from Transgrid's Project Assessment Conclusions Report is 2,570 MW based on a lower VIC to NSW transfer than that used in the ISP.

[51] Transgrid. https://www.transgrid.com.au/media/rxancvmx/transgrid-humelink-pacr.pdf

• A 2000 MW bi-pole overhead transmission line from locality of Bannaby to locality of Wagga Wagga. • A new 2,000 MW bipole converter station in locality of Bannaby. • A new 2,000 MW bipole converter station in locality of Wagga Wagga. • 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 Wagga Wagga and a future Wagga Wagga 500 kV substation. • (Assumption: This option comes after HumeLink)	SNSW to CNSW) N6: 2,000			
Option 3: • An additional new 500 kV double-circuit line from Dinawan to Near Wagga Wagga. • An additional new 500 kV double-circuit line from Near Wagga Wagga to Bannaby. • 4 additional new 500/330/33 kV 1500 MVA transformers at Dinawan. *Pre-requisite: HumeLink, VNI West, SNW Southern 500 kV loop.*	6,000 (both directions SNSW to CNSW) REZ N5+N6: 6,000	2,903	Class 5b (± 50%)	Long
Option 4: • An additional new 500 kV single-circuit line from Dinawan to Near Wagga Wagga. • An additional new 500 kV single-circuit line from Near Wagga Wagga to Bannaby. • 2 additional new 500/330/33 kV 1500 MVA transformers at Dinawan. *Pre-requisite: HumeLink, VNI West, SNW Southern 500 kV loop.*	3,000 (both directions SNSW to CNSW) REZ N5+N6: 3,000	2,279	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Cost estimate provided by Transgrid.	• Cost estimate provided by Transgrid.
Option 2	• Land use: Grazing • Project network element size: Above 200km, # of total Bays 1 - 5 • Location (regional/distance factors): Regional • Delivery Timetable: Long • Greenfield/Brownfield: Greenfield • Jurisdiction: NSW – Southern • Terrain: Hilly/undulating • Proportion of environmentally sensitive areas: 100%	• Known risks: compulsory acquisition high, cultural heritage high, environmental offset risks high, geotechnical findings BAU, macroeconomic influence BAU, market activity tight, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 3	As per option 1	As per option 1
Option 4	As per option 3	As per option 3

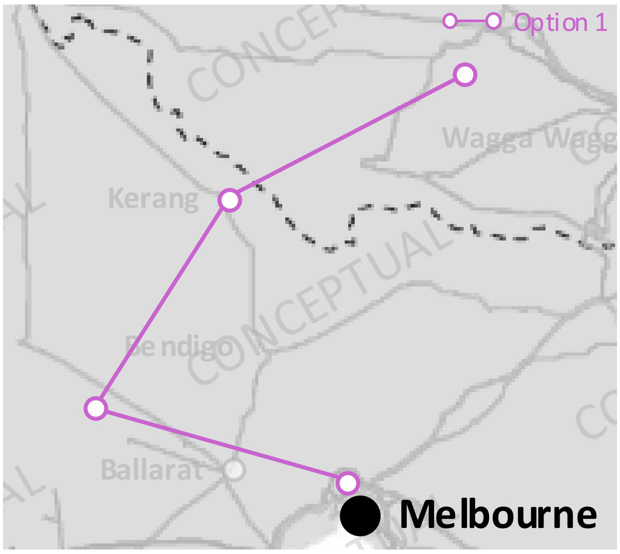
4.9 Victoria to Southern New South Wales

Summary

VNI West was determined to be an actionable ISP project In the 2020 ISP and 2022 ISP, and a RIT-T for this project is in progress. RIT-T proponents are AEMO Victorian Planning (AVP) and Transgrid.

The 2022 ISP identified VNI West (via Kerang) as the ISP candidate option in the ODP. Since publication of 2022 ISP, AVP and Transgrid jointly released VNI West Consultation Report – Options Assessment[52] which proposes Option 5 as the preferred option. 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.

AEMO has based its analysis on Option 5. However, AEMO recognises that there has been significant interest and input on the VNI West Consultation Report – Options Assessment and is still considering input, with a Project Assessment Conclusions Report (PACR) to be published in May. This Draft 2023 *Transmission Expansion Options Report* does not seek to pre-empt the PACR.



Existing network capability

Transfer capability of future options are modelled with VNI minor upgrade & Victoria System Integrity Protection Scheme (SIPS) with battery storage for increased transfer capability from SNSW 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 voltage stability limit. Victoria's SIPS allows to operate the 330 kV line between South Morang and Murray at higher thermal capacity for a short period following a critical contingency.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classificatio n	Lead time
Option 1: • A new 500 kV double-circuit overhead line from Bulgana to near Kerang to Dinawan. • Series compensation on both 500 kV lines between Bulgana to near Kerang. • Upgrade Dinawan – near Wagga Wagga double-circuit line from 330 kV to 500 kV operation (lines build at 500 kV as part of PEC). • Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 MVA transformers • New terminal station near Kerang with two 500/220 kV 1,000 MVA transformers.	North: +1,930 South: +1,650 V2: +850 V3 (WRL timing): +1,460 V3 (WRL & VNI timing): +200 N5: +900	3,282 (June 2020 dollars)[53]	Class 4 (± 30%)	Long

[52] HYPERLINK "https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west-consultation-report---options-assessment.pdf?la=en"vni-west-consultation-report---options-assessment.pdf (aemo.com.au)

[53] Consultation Report – Option Assessment. Available here: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west-consultation-report---options-assessment.pdf?la=en&hash=D86F047ECAD16C6BFC73DDC797ED6789

• 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. • 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 – near Wagga Wagga. • Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang. *Pre-requisite:* WRL 2x500 kV lines from North Sydenham to Bulgana and 2x500/220 kV 1,000 MVA transformers at Bulgana.				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Cost estimate provided by Transgrid and AEMO Victoria Planning.	• Cost estimate provided by Transgrid and AEMO Victoria Planning.

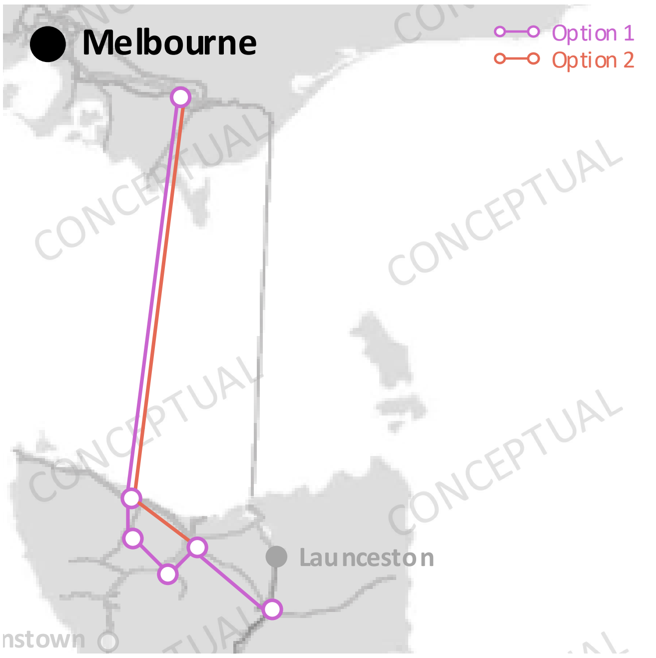
4.10 Tasmania to Victoria

Summary

Marinus Link will deliver two new high voltage direct current (HVDC) cables connecting the Tasmania and Victoria electricity networks, each with 750 MW of transfer capacity and associated high voltage alternating current (HVAC) transmission.

Marinus Link is intended to be connected in the Burnie area in Tasmania and in the Latrobe Valley in Victoria. This project also includes HVAC transmission network developments within the North West Tasmanian electricity network.

Marinus Link was identified as an actionable ISP project in the 2022 ISP. TasNetworks has completed a RIT-T for this network augmentation. The project assessment conclusions report (PACR), the third and final report of the RIT-T, was published in June 2021[54*]. TasNetworks is currently undertaking community engagement, design and approvals on the proposed cable route and transmission lines.



Existing network capability

The transfer capacity between Tasmania and Victoria is limited by the thermal capability of Basslink (HVDC system between Tasmania and Victoria).
Transfer capacity between Tasmania and Victoria is limited to 462 MW (as measured at the receiving end) in both directions at times of peak demand, summer typical and winter reference periods[55].

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)[56]	Cost classification	Lead time
Option 1 (Marinus Link – Stage 1) • A 750 MW monopole HVDC cable between Burnie area in Tasmania and Latrobe Valley in Victoria. • A new 750 MW HVDC monopole converter station in Burnie area. • A new 750 MW HVDC monopole converter station in Latrobe Valley area. • A new 220 kV switching station at Heybridge adjacent to the converter station. • A new 220 kV switching station at Staverton. • A new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie. • A new 220 kV double-circuit line from Palmerston to Sheffield with decommissioning of existing the single-circuit line. • 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 Latrobe Valley to Hazelwood area.	Marinus Link: 750 MW in both directions. Basslink and Marinus Link Stage 1 combined[57]: VIC to TAS 962 MW TAS to VIC 1,212 MW REZ T2: 350 MW REZ T3: 450 MW.	2,380 (June 2021 dollars) (±30%)	Class 4	July 2029

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

[55] In 2022 ISP, 478 MW was applied in both directions. 462 MW transfer in both directions is sourced from Market bids.

[56] Cost estimates are sourced from TasNetworks.

[57] Combined transfer limit from VIC to TAS 462+500=962 MW. This is on an assumption that largest single contingency in Tasmania capped at 500 MW.

Option 2 (Marinus Link – Stage 2) • An additional 750 MW monopole cable between Burnie area in Tasmania and Latrobe Valley in Victoria. • An additional new 750 MW HVDC monopole converter station in Burnie area. • An additional new 750 MW HVDC monopole converter station in Latrobe Valley area. • A new double-circuit 220 kV transmission line from Heybridge to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor. • A new 500 kV connection from converter station in Latrobe Valley to Hazelwood area. *Pre-requisite: TAS-VIC Option 1 (Stage 1)*	Marinus Link: 750 MW in both directions. Basslink and Marinus Link Stages 1 and 2 combined[58]: VIC to TAS 1,712 MW TAS to VIC 1,962 MW REZ T2: 800 MW.	1,402[59] (June 2021 dollars) (±30%) Note: This stage is estimated to cost an additional $600 million if completed more than 3 years after stage 1.	Class 4	July 2031

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Options 1 and 2	• Refer the TasNetworks Marinus Link Cost Estimate Report prepared by Jacobs[60].	

[58] Combined transfer limit from VIC to TAS 462+625+625=1,712 MW. This is on an assumption that largest single contingency in Tasmania capped at 500 MW. Following an outage of Marinus Link cable, the remaining Marinus Link cable increases the transfer by 125 MW to its maximum transfer capacity of 750 MW. This will limit reduction in transfer from VIC to TAS to 500 MW.

[59] For more information on the additional cost of Marinus Link if the second stage is delayed, refer to section 4 of the *Addendum to the Draft 2022 ISP*, at https://aemo.com.au/-/media/files/major-publications/isp/2022/addendum/addendum-to-the-draft-2022-isp.pdf?la=en.

[60] At https://www.marinuslink.com.au/wp-content/uploads/2021/06/Attachment-3-Jacobs-cost-estimate-report.pdf.

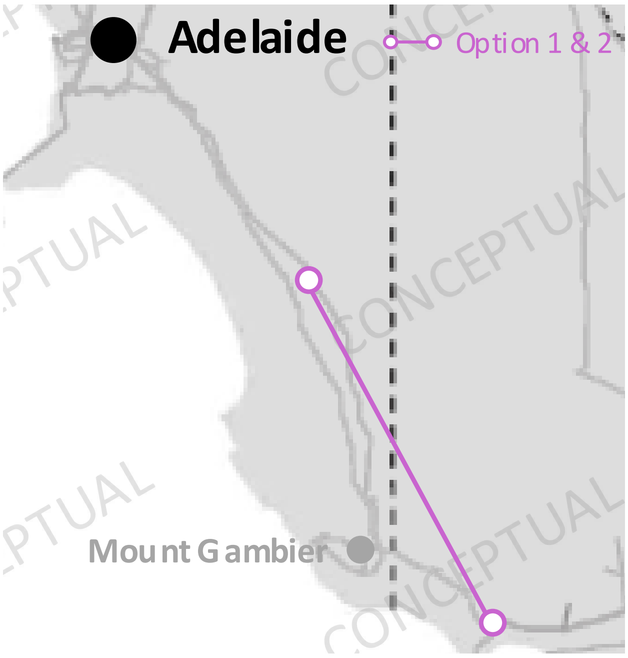
4.11 Victoria to South East South Australia

Summary

The Victoria (VIC) to South East South Australia (SESA) corridor represents VIC-SA 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 REZ to Victoria.

At present this card includes the South Australia options to augment this flow path. AEMO is seeking input from stakeholders, and through joint planning with ElectraNet, to also add any relevant augmentations in the Victoria system for the final Transmission Expansion Options Report.



Existing network capability

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

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build a 275 kV double-circuit line from an offshore collection node in South East SA to Heywood terminal station. • 2x1,000 MVA 500/275 kV transformers at Heywood terminal station. • New offshore collection terminal station.	1640 (VIC to SESA) 1640 (SESA to VIC) S1: 1640 V4: 0 (Transfer limits between Heywood and Sydenham are modelled by a REZ group constraint SWV1)	816	Class 5b (±50%)	Long
Option 2: • Build a 500 kV double-circuit line from an offshore collection node in South East SA to Heywood terminal station. • New offshore collection terminal station. • 2x 1500 MVA 500/275 kV transformers at offshore collection terminal station.	3000 (VIC to SESA) 3000 (SESA to VIC) S1: 3000 V4: 0 (Transfer limits between Heywood and Sydenham are modelled by a REZ group constraint SWV1)	1,084	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied

Option 1	• Land use: Grazing • Project network element size: 100 to 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition -BAU, Environmental offset risks - BAU, Cultural heritage - BAU, Outage restrictions – BAU • Unknown risks: Class 5b
Option 2	As per Option 1.	As per Option 1.

4.12 South East South Australia to Central South Australia

Summary

The South East South Australia (SESA) to Central South Australia (CSA) corridor represents portion of VIC-SA interconnector through Heywood Terminal Station and South East Substation. Development options on this corridor include access of increased renewable generation and energy storage in South East REZ to Adelaide load centre and to New South Wales through NSW-SA interconnector through Bundy and Buronga.

Existing network capability

SESA to CSA maximum transfer capability is 650 MW at peak demand, summer typical and winter reference periods. The maximum transfer capability is limited 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.

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

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build a 500 kV double-circuit line from Bundey terminal station to an offshore collection node in South East SA. • 2x 1,500 MVA 500/275 kV transformers at Bundey terminal station. • New offshore collection terminal station. • 2x 1,500 MVA 500/275 kV transformers at offshore collection terminal station.	3,000 (SESA to CSA) 3,000 (CSA to SESA) S1: 3,000 S2: 0	1,482	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 200 to 300 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition -BAU, Environmental offset risks - BAU, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b

5 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[61] provides an overview of how AEMO uses REZ augmentation options and costs in the ISP modelling.

This section outlines network augmentation options to increase the transfer capacity[62] 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 expansion to establish the REZ. These costs are distinct from the costs associated with individual generator connections, which are considered in Section 1.

This section provides the following information:

- A map of the candidate REZs and network augmentation options for the 2024 ISP (Figure 10).
- A legend and explanation of tables (Section 5.1).
- New South Wales REZ expansion options (Section 5.2).
- Queensland REZ expansion options (Section 5.3).
- South Australia REZ expansion options (Section 5.4).
- Tasmania REZ expansion options (Section 5.5).
- Victoria REZ expansion options (Section 5.6).

Consultation questions

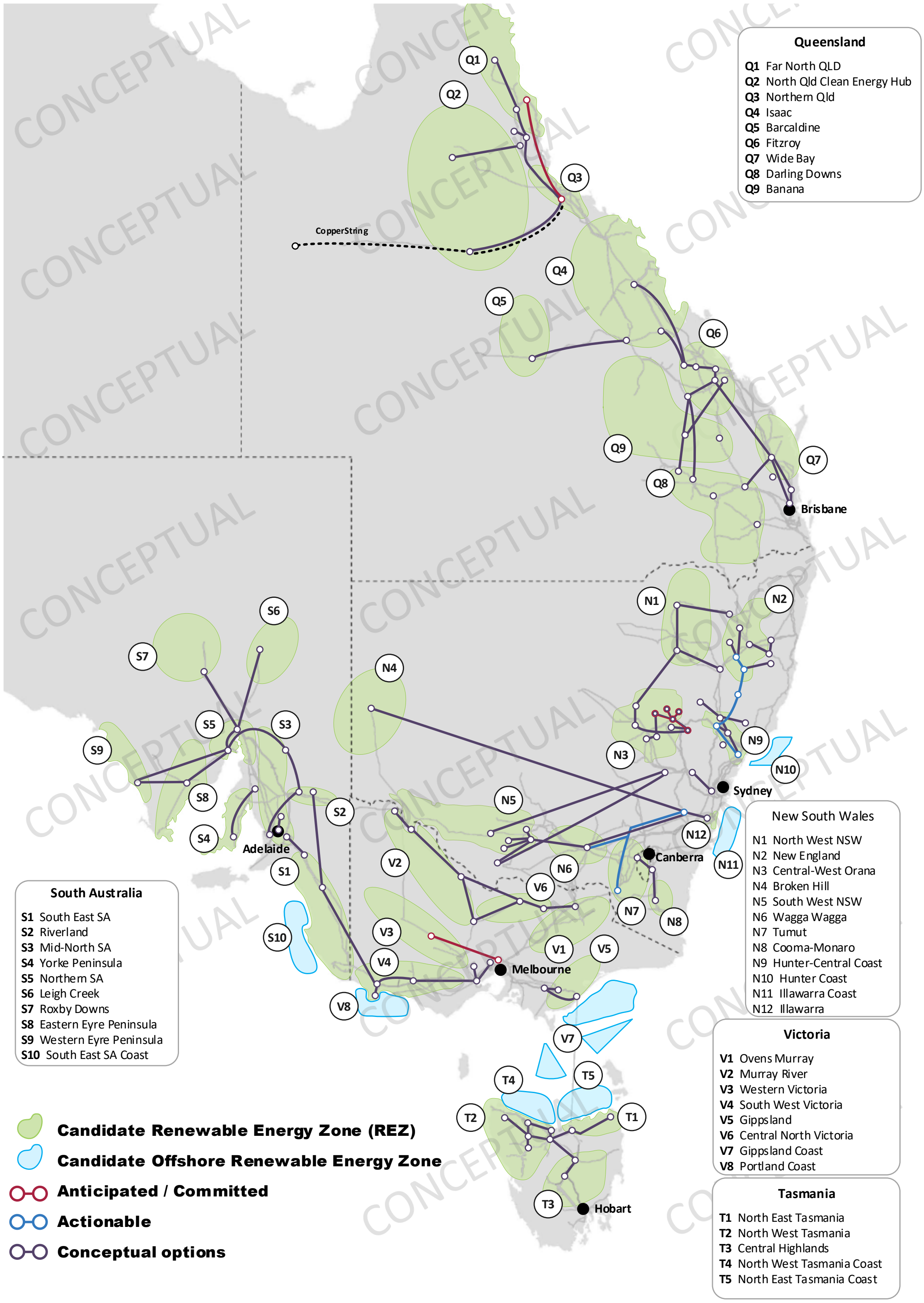
6. Do you have any feedback on the REZ augmentation options provided in this report, including their conceptual design, lead time, location and cost estimates? Please provide evidence to support your feedback.

---

61 AEMO's current ISP Methodology is accessible 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.

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

Figure 10 Candidate REZs and REZ augmentation options for Draft 2023 *Transmission Expansion Options Report*



5.1 Legend and explanation of tables

The tables in Section 4 and Section 5 provide an overview of the characteristics of each network development option. 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 2022 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. The capacity is sourced from recent historical data.
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.
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. For REZs, the power flow is always in one direction from the REZ to the network.</td></tr>
<tr><td>Cost</td><td>The costs are based on 2022 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. 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, 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 2023 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 3.1.</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 2024 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).</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.
• Land use (desert, scrub, grazing and developed area).
• Terrain (flat/farmland, mountainous and hilly/undulating).
• Jurisdiction (state and Rural Bank defined sub-region63).
• 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>
<tr><td colspan="2">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).</td></tr>
</table>

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

• Cultural heritage (BAU, low and high). • Environmental offset risks (BAU, low, high, very high, and observed maximum). • 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).

5.2 New South Wales

5.2.1 North West New South Wales (N1)

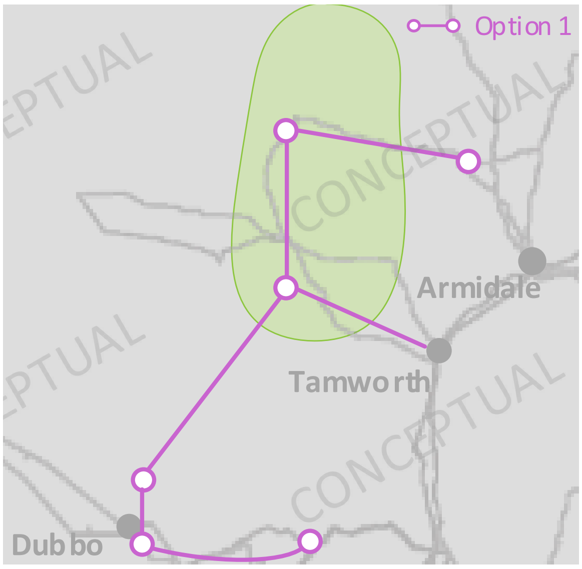
Summary

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)	Cost classification	Lead time
Option 1: • Two new 500 kV circuits from Orana REZ to locality of Gilgandra to locality of Boggabri to locality of Moree. • A new single 500 kV circuit from 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 Orana REZ-locality of Gilgandra, locality of Gilgandra-locality of Boggabri, locality of Boggabri-locality of Moree 500 kV circuits.	1,660	4,356	Class 5b (±50%)	Long

Adjustment factors and risk

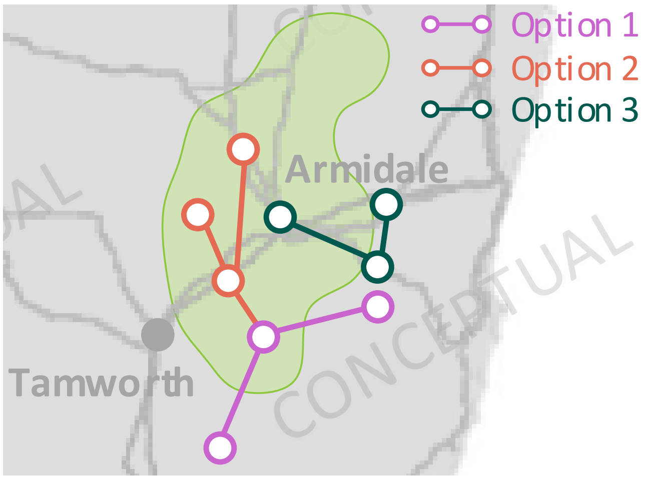
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: Above 200km, no. of bays greater than 31 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight/BAU, Weather delays - BAU, Project complexity – BAU/Partly complex, Compulsory acquisition - BAU/High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b

5.2.2 New England (N2)

Summary

New England REZ is located to the east of and along the existing QNI interconnector. 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 infrastructure development.

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.



Existing network capability

The existing network capacity, following completion of the committed QNI Minor upgrade (see Section 4.5), 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[64]

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 330 kV South (Hub3) and East (Hub 4) switching stations. • New 330 kV double-circuit line between Hub 1 and Hub 3. • New 330 kV double-circuit line between Hub 1 and Hub 4. (Pre-requisite: CNSW-NNSW Option 1)	1,000	345	Class 5b (±50%)	Medium
Option 2[65]: • New North switching station and cuts into Sapphire - Armidale and Dumaresq - Armidale line. • New 500 kV built and initially 330 kV operated double-circuit line from North switching station to Hub 5. • Augment Hub 5 with one additional 500/330 kV transformer. • New 500 kV double-circuit line, strung on one side between Hub 5 to Hub 1. • New 330 kV DCST line from Hub 8 to Hub 5. (Pre-requisite: CNSW-NNSW Option 3)	1,500	965	Class 5b (±50%)	Long
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.	900	612	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied

[64] For practicality of ISP modelling, AEMO has only included a sub-set of the options for this REZ from the September 2022 Draft Network Infrastructure Strategy released by EnergyCo. This does not provide an indication of any ultimate option selection through the New South Wales REZ regulatory process.

[65] The network capacity value for this option is under review between EnergyCo and AEMO. It may be reduced, or require an amended scope, for the final 2023 *Transmission Expansion Options Report*.

Option 1	• Land use: Grazing • Project network element size: 10 – 100km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 100 – 200km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% to 100% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight/BAU, Weather delays - BAU, Project complexity - BAU/Partly complex, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - High/BAU • Unknown risks: Class 5b
Option 3	As per Option 2 above	As per Option 3 above

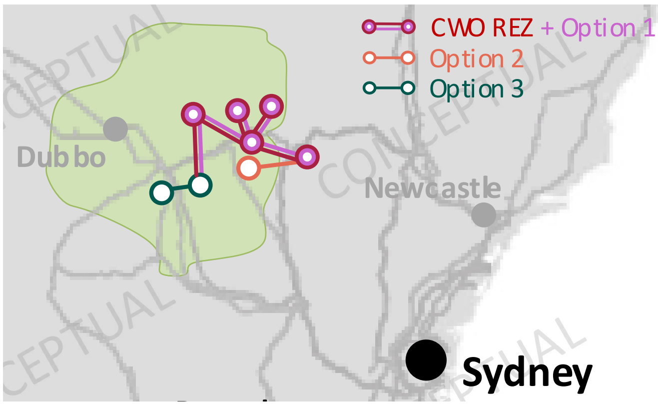
5.2.3 Central-West Orana (N3)

Summary

The Central West Orana REZ is electrically close to the Sydney load centre and has moderate wind and solar resources.

Central West Orana REZ has been identified by the New South Wales Government as the state's first pilot REZ[66].

The *NSW Electricity Infrastructure Investment Act 2020* legislates the REZ be declared with an intended 3,000 MW of additional transmission network capacity.



Existing network capability

The project to establish the Central West Orana REZ is considered anticipated. As such the existing network capability is assumed to be approximately 3,900 MW, incorporating the Central West Orana REZ transmission link project (3,000 MW), as well as existing network capability (900 MW).

Augmentation options[67]

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Central West Orana REZ transmission link • New Merotherie 500/330 kV substation with 3 x 500/330/33 kV 1,500 MVA transformers. • New 330 kV Uarbry East, Uarbry West, Elong Elong switching stations. • New 500 kV Wollar switching station. • 2 x 500 kV double-circuit line from Wollar to Merotherie. • 330 kV double-circuit line from Merotherie to Uarbry East. • 330 kV double-circuit from Merotherie to Uarbry West. • 2 x 500 kV double-circuit and initially operated at 330 kV from Merotherie to Elong Elong. • 3 x 250 MVAr synchronous condensers at Elong Elong switching station. • 4 x 250 MVAr synchronous condensers at Merotherie substation. • Provision of switchbays for future generator connections. • An additional 330 kV single-circuit line from Bayswater to Liddell. • An additional 330 kV single-circuit line from Mt Piper to Wallerawang.	3,000	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: • Expand Elong Elong substation with 3 x 500/330/33 kV 1,500MVA transformers • Expand Merotherie substation with 1 x 500/330/33 kV 1,500MVA transformers • Operate 3 circuits between Elong Elong and Merotherie to 500 kV, while one circuit will continue operating at 330 kV *(Pre-requisite: CWO REZ transmission link project)* Note: Hunter Transmission Project will be required to get up to 6 GW total network capacity as pre-requisite.	3,000	309	Class 5b (±50%)	Medium

[66] See https://www.energyco.nsw.gov.au/renewable-energy-zones#-centralwest-orana-renewable-energy-zone-pilot-.

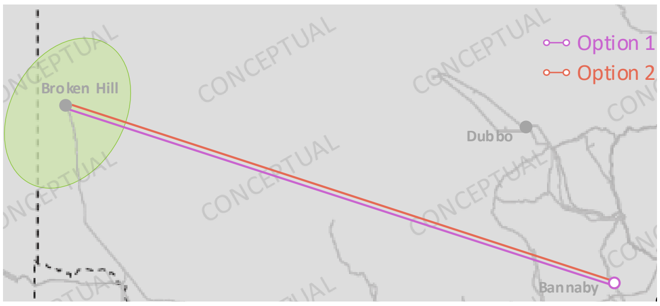
[67] For practicality of ISP modelling, AEMO has only included a sub-set of the options for this REZ from the September 2022 Draft Network Infrastructure Strategy released by EnergyCo. This does not provide an indication of any ultimate option selection through the New South Wales REZ regulatory process.

Note: Hunter Transmission Project will be required when the total network capacity is greater than 3 GW as pre-requisite.				
Option 2: • New 330 kV Stubbo switching station and cuts into Wellington - Wollar • New 330 kV single-circuit line between Wollar and Stubbo • Expand Wollar substation with 330 kV busbar and 1 x 500/300/33 kV 1,500 MVA transformer	500	300	Class 5b (±50%)	Medium
Option 3: • New 330 kV Burrendong switching station and cuts into Line Wellington - Mt Piper • New Uungula switching station and cuts into Wollar - Wellington • New 330 kV double-circuit line from Burrendong switching station to Uungula	500	247	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Optimum	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions – BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 100 to 200km, no. of bays 11-15 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Optimum	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - BAU, Environmental offset risks - BAU, Cultural heritage - BAU, Outage restrictions – High • Unknown risks: Class 5b
Option 3	• Land use: Grazing • Project network element size: 100 to 200km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Optimum	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions – BAU • Unknown risks: Class 5b

5.2.4 Broken Hill (N4)[68]

Summary	
Broken Hill REZ 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.	
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)	Cost classification	Lead time
Option 1: • 500 kV double-circuit line from Bannaby – Broken Hill (>850 km). • Two mid-point switching stations and reactive plant.	1,750	4,767	Class 5b (±50%)	Long
Option 2: • 500 kV double-circuit HVDC line from Bannaby – Broken Hill (>850 km).	1,750	4,209	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: Above 200km, no. of total bays above 31 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b
Option 2	As per Option 1 above	As per Option 1 above

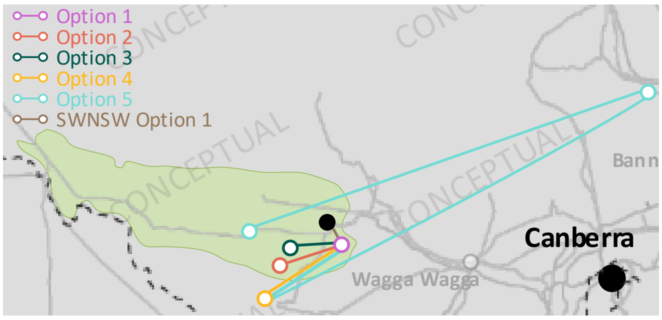
[68] AEMO notes that this REZ is not one of the first five REZs that have been declared by the NSW Government under its New South Wales Electricity Infrastructure Roadmap.

5.2.5 South West NSW (N5)

Summary

The South West REZ has good solar resource and incorporates the Dinawan 330 kV substation that will be built as part of Project EnergyConnect.. Further west, the 220 kV links to North West Victoria and Broken Hill. This REZ is one of three REZs which are being targeted for further development under the NSW Electricity Infrastructure Roadmap.

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 l imit.



Existing network capability

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. 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 projects. Furthermore, one option for VNI West (Kerang route) would also increase the capacity of this REZ.

Augmentation options[69]

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Expand Dinawan 330 kV switching station to 500/330 kV substation with 3 x 500/330/33 kV, 1,500 MVA transformers • Operate 500 kV build and 330 kV operated double-circuit line from Dinawan to Wagga to 500 kV *(Pre-requisite: EnergyConnect and HumeLink)*[70]	2,500	1,215	Class 5b (±50%)	Long
Option 2: • New Congaro 330 kV switching station • New 330 kV double-circuit line from Congaro to Dinawan *(Pre-requisite: Dinawan - Wagga 500 kV upgrade)*	800	327	Class 5b (±50%)	Long
Option 3: • New Marbins Well 330 kV switching station • New 330 kV DCST line from Mabins Well to Dinawan *(Pre-requisite: Dinawan - Wagga 500 kV upgrade)*	1,400	257	Class 5b (±50%)	Long
Option 4: • New The Plains 330 kV switching station • New 330 kV double-circuit line and strung on one side from The Plains to Dinawan (Pre-requisite: South West REZ Option 1)	1,400	357	Class 5b (±50%)	Long
Option 5:			Class 5b (±50%)	Long

[69] For practicality of ISP modelling, AEMO has only included a sub-set of the options for this REZ from the September 2022 Draft Network Infrastructure Strategy released by EnergyCo. This does not provide an indication of any ultimate option selection through the New South Wales REZ regulatory process.

[70] Option 1 is an alternative to VNI West Project

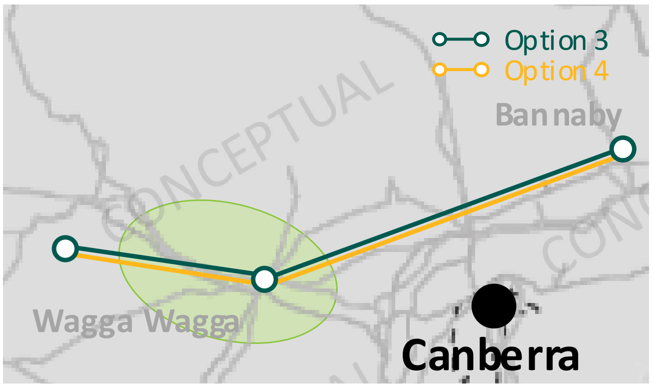
• New Hays Plain 330 kV switching station • New Abercrombie 330 kV switching station • New 330 kV double-circuit line from Hays Plain to Abercrombie • New 330 kV double-circuit line from Abercrombie to The Plain • String the other side of 330 kV line from The Plain to Dinawan (Pre-requisite: South West REZ Option 4)	1,400	897		
SWNSW1 Option 1: • Establish a new Darlington Point to Dinawan 330 kV transmission line, post Project EnergyConnect *(Pre-requisite: Project EnergyConnect and HumeLink)*	600	167[71]	Class 5a (± 30%)	Short

Adjustment factors and risk

Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: 100 to 200km, no. of total bays 6 – 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - High, Environmental offset risks - Very high, Cultural heritage - High, Outage restrictions - High • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 10 to 100km, no. of total bays 1 – 5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High, Environmental offset risks - Very high, Cultural heritage - High, Outage restrictions – High • Unknown risks: Class 5b
Option 3	As per Option 2 above	As per Option 2 above
Option 4	As per Option 2 above	As per Option 2 above
Option 5	• Land use: Grazing • Project network element size: Above 200km, no. of total bays 6 – 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High, Environmental offset risks - Very high, Cultural heritage - High, Outage restrictions – High • Unknown risks: Class 5b
SWNSW1 Option1	• Transgrid Project Assessment Conclusions Report RIT-T estimate	• Transgrid PACR RIT-T estimate

[71] Cost Estimate from Transgrid PACR at https://www.transgrid.com.au/media/tinisujc/transgrid-pacr_improving-stability-in-sw-nsw.pdf.

5.2.6 Wagga Wagga (N6)[72]

Summary	
This REZ extends to the west of Wagga Wagga and has moderate wind and solar resources.	
Existing network capability	
There is no additional capacity within this REZ due to congestion in the surrounding 330 kV networks. Further development of new generation in this REZ requires network augmentation towards the greater Sydney load centre. Additionally, the capacity within this REZ and ability to transfer energy from the REZ to the main load centres in the greater Sydney area are improved with the proposed HumeLink project. Options shown do not depend upon HumeLink as a pre-requisite.	

Augmentation options

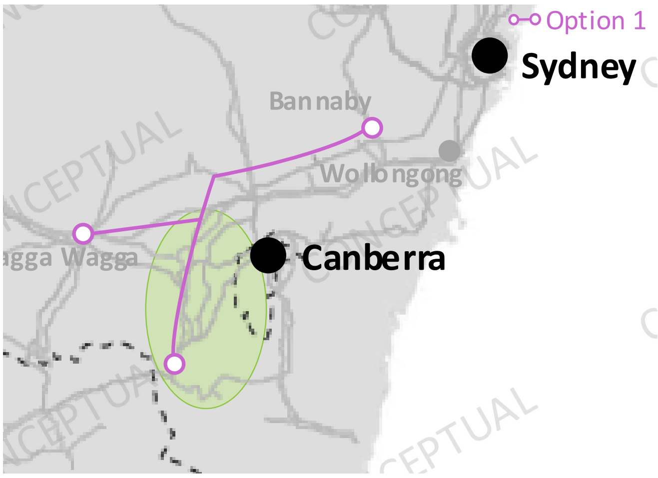
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Refer to SNSW-CNSW Option 3 and 4 in the flow paths				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Refer to SNSW-CNSW Option 3 and 4 in the flow paths	

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

5.2.7 Tumut (N7)[73]

Summary	
The Tumut REZ has been identified due to the potential for additional pumped hydro generation in association with Snowy 2.0 and the proposed actionable ISP HumeLink. The HumeLink project † will enable the connection of more than 2,000 MW of pumped hydro generation (Snowy 2.0) in the Tumut REZ area.	
Existing network capability	
There is no additional capacity within this REZ. Further development of new generation in this REZ is associated with the HumeLink project. Currently the 330 kV transmission network around Lower and Upper Tumut is congested during peak demand periods. A careful balance of generation from the existing hydro units and flow between Victoria and New South Wales is required to prevent overloads within this area.	

Augmentation options

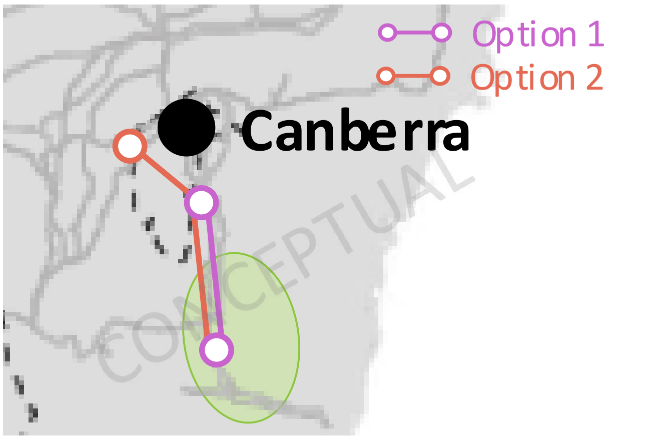
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • HumeLink (Actionable ISP 2020 project- see Section 3.7).	2,200(SNSW to CNSW) REZ network limit increase: 1,500 MW in N6, 2,200 MW in N6+N7, 1,000 MW in N5.	See Section 4.9 3,317 (June 2020 dollars) (including $330 million for early works‡)		

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	See Section 3.7	

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

5.2.8 Cooma-Monaro (N8)

Summary	
The Cooma-Monaro REZ has been identified for its pumped hydro potential. This REZ has moderate to good quality wind resources.	
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)	Cost classification	Lead time
Option 1: • 132 kV single-circuit Williamsdale to Cooma-Monaro substation (located near generation interest)	150	184	Class 5b (±50%)	Medium
Option 2: • 330 kV line Cooma-Williamdale-Stockdill • Two 330/132 kV transformers at Cooma	500	495	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 to 100km, no. of total bays 1 - 5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 10 to 100km, no. of total bays 6 - 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	As per Option 1 above

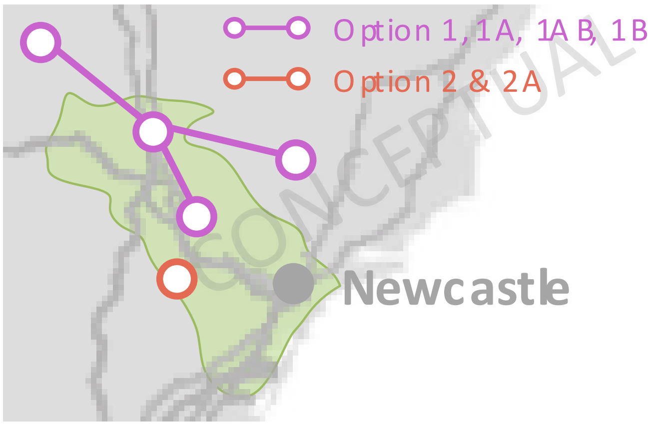
5.2.9 Hunter-Central Coast (N9)

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 1,000MW of intended network capacity 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.



Existing network capability

This REZ is intended to supply SNW and it is assumed that supply to SNW would also include high southbound flows from NNSW to CNSW. The REZ limit is at 400 MW to reflect the limit for supplying SNW.

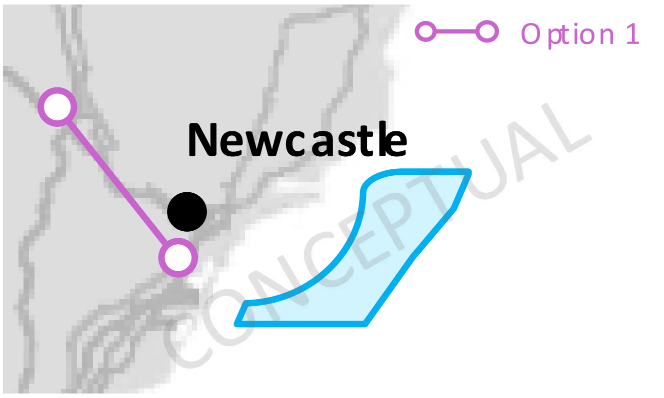
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Rebuild the existing Line 83 Liddell - Muswellbrook as 330 kV double-circuit line • 1 x 330 kV double-circuit from East Hub to Muswellbrook • 1 x 330 kV double-circuit from West Hub to Muswellbrook	950	287	Class 5b (±50%)	Medium
Option 1A • Install a new 330 kV circuit between Liddell and Muswellbrook, Twin Olive conductor • 1 x 330 kV DCST from East Hub to Muswellbrook conductor • 1 x 330 kV DCST from West Hub to Muswellbrook	950	265	Class 5b (±50%)	Medium
Option 1AB • Install a new 330 kV circuit between Liddell and Muswellbrook • 1 x 330 kV DCST from East Muswellbrook Hub to Muswellbrook • Build 330/132 kV 375 MVA transformer at West Muswellbrook Hub • 1 x 132 kV DCST from West Muswellbrook Hub to Muswellbrook	850	267	Class 5b (±50%)	Medium
Option 1B • Rebuild the existing Line 83 Liddell - Muswellbrook as 330 kV double-circuit line • 1 x 330 kV DCST from East Muswellbrook Hub to Muswellbrook • Build 330/132 kV 375MVA transformer at West Muswellbrook Hub • 1 x 132 kV DCST from West Muswellbrook Hub to Muswellbrook	850	290	Class 5b (±50%)	Medium
Option 2: • New 330 kV Singleton switching station and cuts into line 82 Liddell - Tomago	500	56	Class 5b (±50%)	Short
Option 2A	375	117		Medium

• New 330/132 kV 375 MVA Singleton two transformer substation and cuts into line 82 Liddell - Tomago and connected to Ausgrid's Singleton 132 kV substation switching station				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: 10 to 100km, no. of total bays 11 - 15 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU • Unknown risks: Class 5b
Option 1A	• Land use: Grazing • Project network element size: 10 to 100km, no. of total bays 6 - 10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	As per Option 1 above
Option 1AB	As per Option 1 above	As per Option 1 above
Option 1B	As per Option 1 above	As per Option 1 above
Option 2	• Land use: Grazing • Project network element size: Below 1km, no. of total bays 1 - 5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Remote • Delivery Timetable: Long	Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - BAU, Compulsory acquisition - High/BAU, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU
Option 2A	As per Option 2 above	As per Option 2 above

5.2.10 Hunter Coast (N10)

Summary	
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.	
Existing network capability	
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.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • CNSW – SNW Option 1 in Section 3.7 (Northern 500 kV loop) or the Hunter Transmission Project would provide additional offshore wind generation from the existing limit of 5,500 MW.	2,000	Refer to Section 4.7 Option 1	Class 5b (±50%)	Long

Adjustment factors and risk

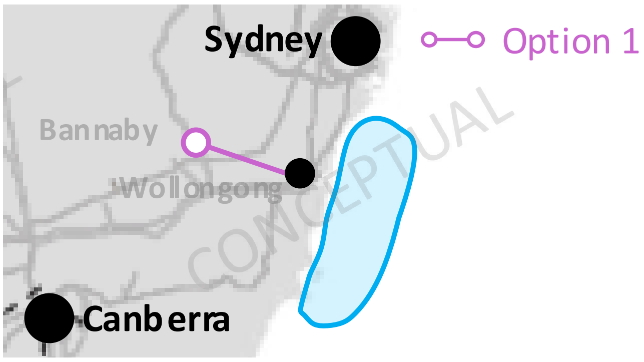
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	See Section 3.7 (Central New South Wales to Sydney, Newcastle and Wollongong)	

5.2.11 Illawarra Coast (N11)

Summary

To be able to facilitate large amounts of offshore wind connecting in this part of the 330 kV network, it is anticipated that expansion will be required to connect to the 500 kV backbone.

The REZ has been declared with 1,000MW 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 current network transfer capacity is approximately 1,000 MW. This capacity could also be shared with any new generation connecting in the Illawarra REZ.

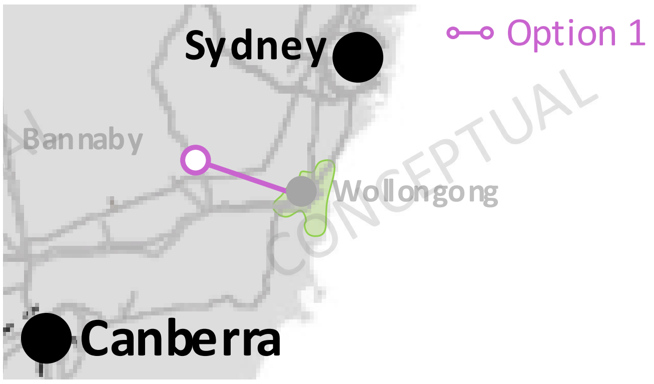
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 500 kV double-circuit line from Dapto – Bannaby. • Two 500/330 kV 1,500 MVA transformers at Dapto. (*Pre-requisite: CNSW – SNW Option 2*)	2,000	783	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Developed area / Scrub • Project network element size: 100km to 200km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional / Urban • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - BAU/High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU/High • Unknown risks: Class 5b

5.2.12 Illawarra (N12)

Summary	
The Illawarra REZ was formally declared by the Minister for Energy in NSW on 27 February 2023[74]. 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.	
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[75]

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 500 kV double-circuit line from Dapto – Bannaby. • Two 500/330 kV 1,500 MVA transformers at Dapto. (*Pre-requisite: CNSW – SNW Option 2*)	2,000	783	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Developed area / Scrub • Project network element size: 100km to 200km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional / Urban • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - Tight, Weather delays - BAU, Project complexity - Partly complex, Compulsory acquisition - BAU/High, Environmental offset risks - High, Cultural heritage - BAU, Outage restrictions - BAU/High • Unknown risks: Class 5b

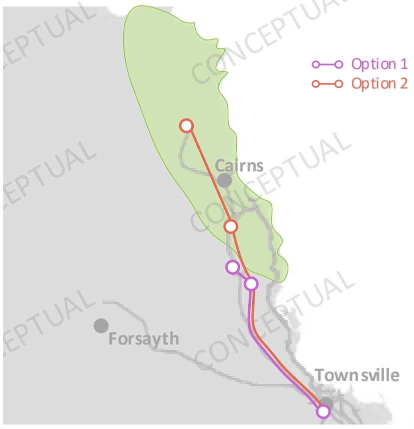
[74] EnergyCo, Illawarra Renewable Energy Zone, at: https://www.energyco.nsw.gov.au/ilw-rez.

[75] While EnergyCo does not currently have network options for this REZ in its Network Infrastructure Strategy document, AEMO will continue to consult with EnergyCo and incorporate any additional options prior to the final 2023 *Transmission Expansion Options Report*.

5.3 Queensland

5.3.1 Far North Queensland (Q1)

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. Two options are proposed that progressively increase network capacity and allow for upgrades based on where generation develops.
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

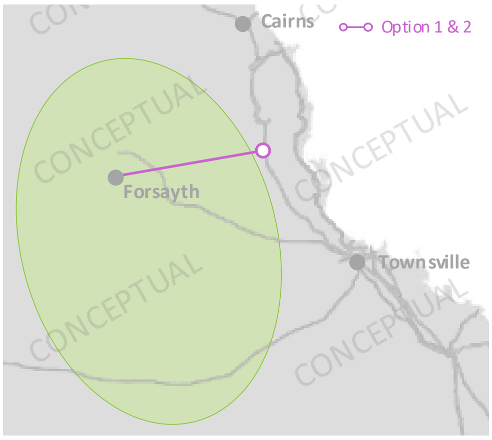
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Establish a new 275 kV substation north of Millstream. • Build a 275 kV double-circuit line from Chalumbin to Millstream. • Rebuild the double-circuit Chalumbin–Ross 275 kV line at a higher capacity (possibly timed with asset replacement). • Build additional Chalumbin-Ross 275 kV double-circuit tower but switch as a single-circuit line (energise second line as generation develops)	1,290	1,663	Class 5b (±50%)	Long
Option 2: • 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–Walkamin single-circuit line. • Rebuild the double-circuit Chalumbin–Ross 275 kV line at a higher capacity (possibly timed with asset replacement). • Build additional Chalumbin-Ross 275 kV double-circuit tower but switch as a single-circuit line (energise second line as generation develops)	1,290	2,541	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: scrub • Project network element size: above 200km • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): regional • Delivery Timetable: long • Greenfield or Brownfield: partly brownfield • Jurisdiction: QLD- North • Location wind loading zones: cyclone region • Terrain: hilly/undulating	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BA, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b

Option 2	As per option 1, except: • Location (regional/distance factors): partially regional and partially remote	As per option 1

5.3.2 North Queensland Clean Energy Hub (Q2)

Summary	
The Clean Energy Hub REZ is at the north-western section of Powerlink's network, and has excellent wind and solar resources.	
Existing network capability	
The current total REZ transmission limit for existing and new VRE before any network upgrade in North Queensland Clean Energy Hub is approximately 700 MW for peak demand, summer typical and winter reference conditions.	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Option 1: • Establish a 275 kV yard at Kidston substation near Forsayth. • Build a 275 kV double-circuit line from Kidston to a mid-point switching station on the Ross-Chalumbin (energise only a single line until generation in the REZ develops).	500	547	Class 5a (±30%)	Medium
Option 2: • Energise the second circuit on the line established in Option 1. • Additional reactors if required. *Pre-requisite: Q2 Option 1*	1,000	Nil	Class 5b (±50%)	Medium

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: desert • Project network element size: 100km to 200km • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): remote • Delivery Timetable: long • Greenfield or Brownfield: greenfield • Jurisdiction: QLD- North • Location wind loading zones: cyclone region • Terrain: flat/farmland	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BA, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5a

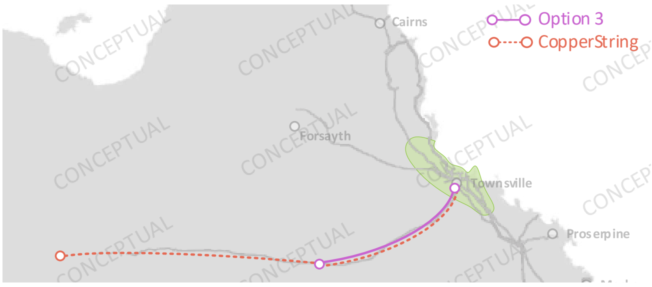
5.3.3 Northern Queensland (Q3)

Summary

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.

The Queensland Government has announced that it will deliver the 1,100 km CopperString 2.0 project. CopperString will connect the North-West Minerals Province of Queensland to the National Electricity Market via Woodstock near Townsville. The project scope includes transmission capacity between Townsville and Hughenden to unlock the renewable energy potential of the region.

AEMO has noted the CopperString project in this table and map, and will continue discussions with the Queensland Government and Powerlink to understand the status of the project as it progresses.



Existing network capability

Existing network capacity can allow for up to approximately 1,200 MW of new generator connections, shared between Q1, Q2 and Q3. The existing network at the North-West Mineral Province is an isolated electrical island. The NEM only extends as far West as Julia Creek and is mainly energised at 66 kV in that area, with two local generation projects only. The existing network for this REZ was designed to support North-West Queensland load, rather than building for future generation projects. The current network can potentially support much more generation within this REZ.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 and Option 2: see section 3.2 (Central Queensland and Northern Queensland flow path augmentations)				
Option 3: • Prerequisite: CQ-NQ Option 2 (QEJP) • Establish a new 500 kV substation at Hughenden with associated switchgear and bays. • A new 500 kV 3,000MVA double-circuit line between locality of Townsville and Hughenden • Limit extension special protection scheme (similar to a virtual transmission line). Cost of non-service agreement excluded.	2,500	1,927	Class 5b (±50%)	Long

Adjustment factors and risk

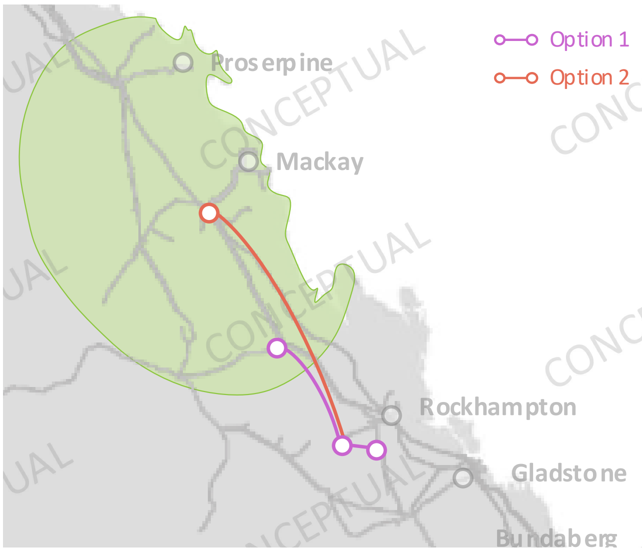
Option	Adjustment factors applied	Known and unknown risks applied
Option 1 and Option 2: see section 3.2 (Central Queensland to Northern Queensland flow path augmentations)		
Option 3	• Land use: desert • Project network element size: above 200km • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): remote • Delivery Timetable: long • Greenfield or Brownfield: greenfield • Jurisdiction: QLD- North • Location wind loading zones: cyclone region • Terrain: flat/farmland	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BA, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b

5.3.4 Isaac (Q4)

Summary

The Isaac REZ has good wind and solar resources covering Collinsville and Mackay, 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.

The Queensland Government has announced that, subject to final investment decisions, it will build a 5,000 MW / 24-hour Pioneer-Burdekin pumped hydro energy storage project in this area near the Burdekin shire, as part of the Queensland SuperGrid.



Existing network capability

The Isaac REZ forms part of the NQ transmission backbone from Nebo to Strathmore. Due to the existing high voltage infrastructure there are no augmentation options specifically for this REZ. The associated augmentations are the NQ2 and NQ3 group constraint augmentations that facilitate power Q1 to Q5 to be transmitted south to the load centres (see Section 4.3.10).

The network has the ability to support up to a total of 2,500 MW of generation in Summer peak and Summer typical conditions and 2,750 MW for Winter reference conditions across the REZs in northern Queensland.

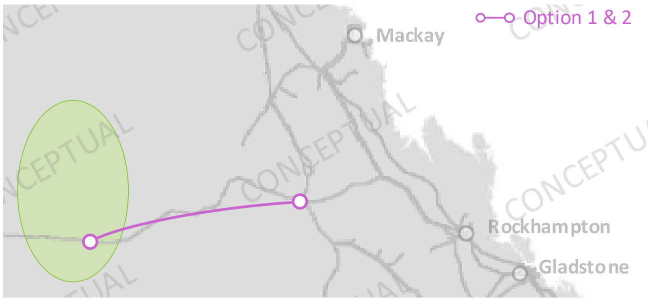
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.3.10 (NQ2 group constraint augmentations)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.3.10 (NQ2 group constraint augmentations)		

5.3.5 Barcaldine (Q5)

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.	

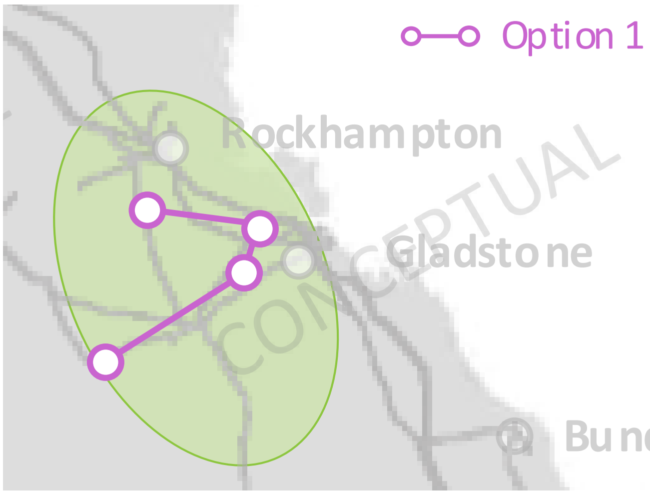
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Establish a 275 kV substation in the Barcaldine region • Build a 300 km 275 kV double-circuit line from Lilyvale to Barcaldine (energise only a single line until generation in the REZ develops).	500	997	Class 5b (±50%)	Long
Option 2: • Energise the second circuit on the line established in Option 1. • Additional substation bays and reactors. *Pre-requisite: Q5 Option 1*	1,000	Nil	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: desert • Project network element size: above 200km • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): remote • Delivery Timetable: long • Greenfield or Brownfield: greenfield • Jurisdiction: QLD- Central • Location wind loading zones: cyclone region • Terrain: flat/farmland	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BA, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 2	As per option 1	As per option 1

5.3.6 Fitzroy (Q6)

Summary	
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.	
Existing network capability	
Network capability to export electricity to southern Queensland is shared between VRE generation within Fitzroy REZ and other generation within northern and central Queensland, particularly at Gladstone. This network 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. 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 (see Section 3.3)	

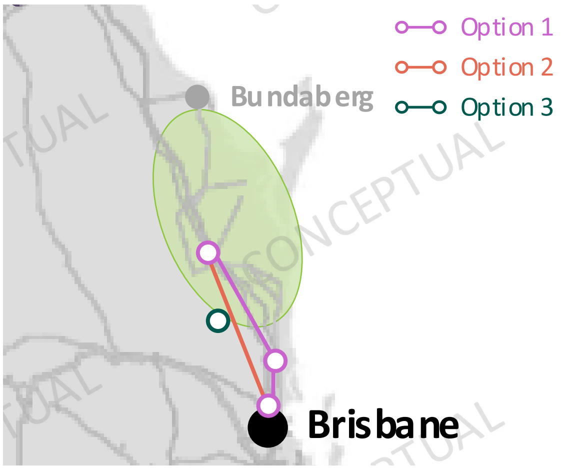
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 3.3 (Central Queensland to Gladstone Grid flow path augmentations)				

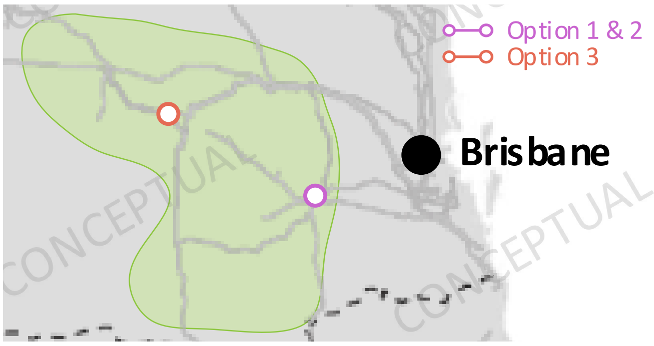
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 3.3 (Central Queensland to Gladstone Grid flow path augmentations)		

5.3.7 Wide Bay (Q7)

<table>
<tr><th colspan="5">Summary</th></tr>
<tr><td colspan="2">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="3" rowspan="3">
</td></tr>
<tr><th colspan="2">Existing network capability</th></tr>
<tr><td colspan="2">The existing network facilitates power transfer from Central Queensland to the load centre in Brisbane. This is a 275 kV transmission backbone and can support up to approximately 1,400 MW of power flow into Brisbane during summer peak, summer typical and winter reference conditions, with maximum VRE output in the REZ being dependant 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>Cost classification</th><th>Lead time</th></tr>
<tr><td colspan="5">See Section 4.3.10 (SQ1 group constraint augmentations)</td></tr>
<tr><th colspan="5">Adjustment factors and risk</th></tr>
<tr><th>Option</th><th>Adjustment factors applied</th><th colspan="3">Known and unknown risks applied</th></tr>
<tr><td colspan="5">See Section 4.3.10 (SQ1 group constraint augmentations)</td></tr>
</table>

5.3.8 Darling Downs (Q8)

<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="4">
</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.

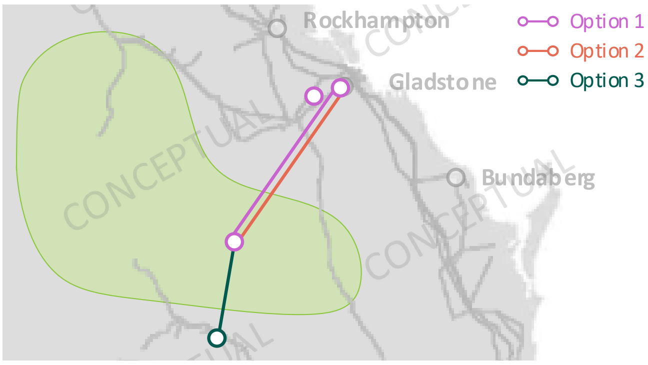
The existing network facilitates power transfer from south west Queensland to the load centre in Brisbane. This transmission can support up to approximately 5300MW of generation into Brisbane during summer peak, summer typical and winter reference conditions. However this capability is significantly reduced depending on the output of existing coal and gas generation in the REZ, 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></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>Cost classification</th><th>Lead time</th></tr>
<tr><td colspan="5">See Section 5.3.10 (SWQLD1 transmission limit constraint augmentations)</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 colspan="5">See Section 5.3.10 (SWQLD1 transmission limit constraint augmentations)</td></tr>
</table>

5.3.9 Banana (Q9)

Summary

The Banana REZ is located roughly 200 km south-west of Gladstone and lies north of the CQ-SQ flow path (see Section 3.4). 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 location both within the Banana REZ and the connection point within the Gladstone section 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.

Augmentation options[76]

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	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 CQ-SQ Option 5. • Additional 500/275 kV 1,500 MVA transformer at the CQ substation. • Switchgear at the existing Gladstone substation. Connection from Gladstone to the new Gladstone substation. *Pre-requisite: CQ-SQ Option 5*	3,000	1,009	Class 5b (±50%)	Long
Option 2: • Establish a new 275 kV substation within the Banana REZ. • 200 km double-circuit 275 kV line from Banana REZ to a substation near Gladstone. Switchgear at the substation near Gladstone.	1,000	606[1]	Class 5b (±50%)	Medium
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.	1,000	601[1]	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: grazing • Project network element size: above 200km • Proportion of environmentally sensitive areas: None	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BA, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU

[76] Banana REZ expansion options are understood to be likely to be dedicated network assets which connect VRE in the region to either CQ or NQ. As such, AEMO is likely to model these options similar to generator connection assets rather than REZ network expansions in the ISP model.

	• Location (regional/distance factors): regional • Delivery Timetable: optimum • Greenfield or Brownfield: greenfield • Jurisdiction: QLD- Central • Location wind loading zones: non-cyclone region • Terrain: flat/farmland	• Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 2	As per option 1	As per option 1
Option 3	As per option 1, except: • Project network element size: 100 km to 200 km	As per option 1

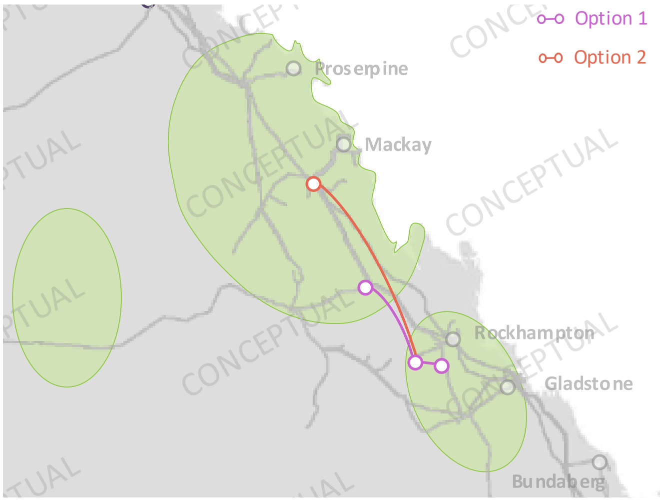
5.3.10 Queensland group constraints and transmission limit constraints

NQ2 Group constraint

Summary

Upgrade options associated with the Group Constraint NQ2 may be built to improve the generation capacity in Northern Queensland, Q1 to Q5. These augmentations will facilitate transmission of this generation to load centres in the south.

The Queensland Government has announced that, subject to final investment decisions, it will build a 5,000 MW / 24-hour Pioneer-Burdekin pumped hydro energy storage project in this area near the Burdekin shire, as part of the Queensland SuperGrid.



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 2,500 MW of generation during summer peak and summer typical conditions and 2,750 MW during winter reference conditions.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Construct additional 275 kV circuit from Bouldercombe – Stanwell. • String and energise the second Broadsound-Stanwell 275 kV additional circuit (on existing DCST).	400	149	Class 5b (±50%)	Medium
Option 2: • Additional 275 kV double-circuit lines between Central and North Queensland	1,400	910	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: scrub • Project network element size: 100 km to 200 km • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): regional • Delivery Timetable: long • Greenfield or Brownfield: partly brownfield • Jurisdiction: QLD- Central • Location wind loading zones: non-cyclone region • Terrain: hilly/undulating	• Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, macroeconomic influence BAU, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 2	As per option 1	As per option 1

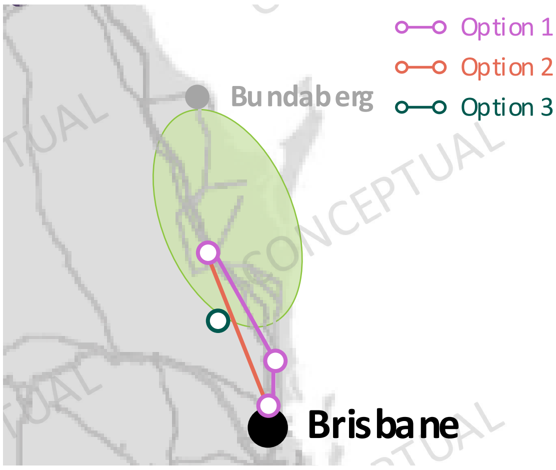
SQ1 Group constraint

Summary

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 Government has announced that, subject to final investment decisions, it will build a 2,000 MW / 24-hour Borumba pumped hydro energy storage project in southern Queensland, as part of the Queensland SuperGrid.

This 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. I



Existing network capability

This is a 275 kV transmission backbone and can support up to approximately 1,400 MW of flow into Brisbane during summer peak, summer typical and winter reference conditions, with maximum VRE output in the REZ being dependant on CQ-SQ flows.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Rebuild Woolooga – Palmwood - South Pine 275 kV single-circuit line as a high-capacity double-circuit line. • 100 MVAr reactor for voltage control.	1,100	499[77]	Class 5b (±50%)	Long
Option 2: • Rebuild Woolooga – South Pine 275 kV single-circuit line as a high-capacity double-circuit line • 100 MVAr reactor for voltage control	1,100	576[78]	Class 5b (±50%)	Long
Option 3: • Prerequisite is CQ-SQ Option 5 • New 500 kV substation at Borumba • Cut-in Halys-Woolooga West 500 kV line at Borumba	1,700[79]	83	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: grazing • Project network element size: 100km to 200km • Proportion of environmentally sensitive areas: 25 percent • Location (regional/distance factors): regional	• Known risks: compulsory acquisition low, cultural heritage low, environmental offset risks low, geotechnical findings low, macroeconomic influence BAU, market activity BAU, outage restrictions BAU, project complexity BAU, weather delays BAU

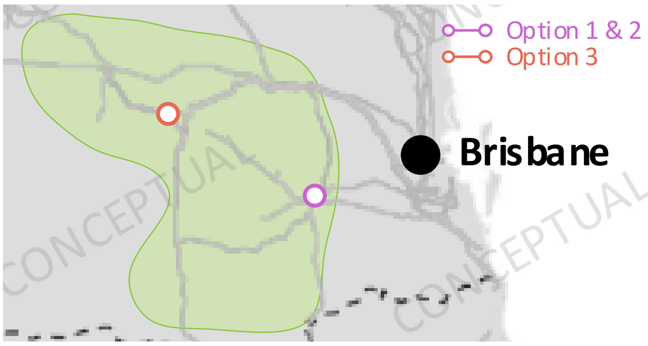
[77] This cost estimate assumes zero costs for acquiring property and for environmental offsets because it is a line rebuild project. As stated in Q7, the existing easement is double width and so the new double-circuit could be built in situ next to the existing circuit to limit outage constraints and market impact. As a result, the attached Transmission Cost Database cost estimate output file for this option will include a larger cost estimate than what is reported here.

[78] Due to this cost being a line rebuild, the easement is already partially acquired by Powerlink. Therefore, the cost of acquiring property and environment offset costs has been reduced by 30%. However, this is only a single width easement, so the existing line would have to be removed before a new double-circuit could be built. This work would incur significant market impact.

[79] This expansion capacity represents the synthesis of studies across a range of different network conditions to determine the additional hosting capability of the REZ with Borumba PHES already added. This number does not represent a hard 1700 MW limit on Borumba output.

	• Delivery Timetable: long • Greenfield or Brownfield: partly brownfield • Jurisdiction: QLD- South • Location wind loading zones: non-cyclone region • Terrain: hilly/undulating	• Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 2	As per option 1	As per option 1, except: • Known risks: environmental offset risks BAU • Known risks: outage restrictions HIGH
Option 3	As per option 1, besides: • Delivery timetable: tight • Project network element size: less than 1km	As per option 1, except: • Known risks: compulsory acquisition BAU, cultural heritage BAU, environmental offset risks BAU, geotechnical findings BAU, market activity tight

SWQLD1 transmission limit constraint

Summary	
Upgrade options associated with the transmission limit constraint SWQLD1 may be built to improve the generation capacity in south west Queensland. These augmentations will facilitate transmission of this generation to load centres in the locality of Brisbane.	
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. However this capability is significantly reduced depending on the output of existing coal and gas generation in the REZ, the flow of power from New South Wales, and the flow of power from central Queensland.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Replace existing 1,300 MVA 330/275 kV transformer at Middle Ridge with 1,500 MVA 330/275 kV transformer. • Implement post-contingent bus splitting scheme at Middle Ridge.	500	52	Class 5b (±50%)	Short
Option 2: • Implement post-contingent bus splitting scheme at Middle Ridge. • Build a 300 MW battery energy storage system	300	Non-network projects are not estimated as part of the Transmission Expansion Options Report.		
Option 3: • Prerequisite is NNSW-SQ Option 5 and CQ-SQ Option 5 and SQ1 option 3 • New 2x 500/275 kV transformers at Western Downs with associated switchgear and bays • Cut-in 500 kV DCST lines from Halys to NNSW and associated switchgear and bays	1,500	173	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: grazing • Project network element size: # of total bays 1-5 • Proportion of environmentally sensitive areas: none • Location (regional/distance factors): regional • Delivery Timetable: long • Greenfield or Brownfield: brownfield • Jurisdiction: QLD- South • Location wind loading zones: non-cyclone region	• Known risks: compulsory acquisition low, cultural heritage low, environmental offset risks BAU, geotechnical findings low, macroeconomic influence BAU, market activity BAU, outage restrictions high, project complexity BAU, weather delays BAU • Unknown risks: Plant procurement cost risks, Productivity and labour cost risks, Project overhead risks, Scope and technology risks all class 5b
Option 2	Non-network projects are not estimated as part of the Transmission Expansion Options Report.	
Option 3	As per option 1, except:	As per option 1, except:

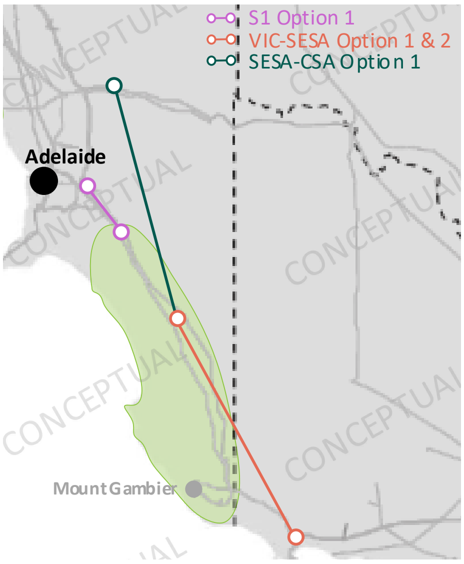
	• Terrain: flat/farmland • Proportion of environmentally sensitive areas: 25 percent • Delivery Timetable: tight • Greenfield or Brownfield: partly brownfield • Project network element size: # of total bays 1-5 and below 1km	• Known risks: compulsory acquisition BAU, cultural heritage BAU, geotechnical findings BAU, outage restrictions BAU

5.4 South Australia

5.4.1 South East SA (S1)

Summary

The South East SA 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.



Existing network capability

The existing network capacity of this REZ is modelled as part of SESA-CSA sub-regional maximum transfer capability of 650 MW. Further network augmentation is required to allow additional generation to be built. Network augmentations would be smaller if generation is located relatively close to Adelaide, and larger if located further south towards Mount Gambier.

There are no augmentation options specifically for this REZ. The associated augmentations are the VIC-SESA & SESA-CSA flow path augmentations (see Sections 3.11 and 3.12).

Augmentation options

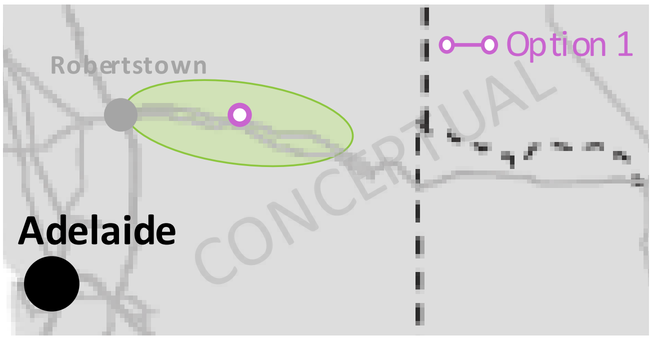
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 (part of preparatory activities): • String vacant circuit on the 275 kV Tungkillo – Tailem Bend line. • Assumes following NCIPAP project in place: Turn in 275 kV circuit Tailem Bend to Cherry Gardens at Tungkillo[80].	To be completed by ElectraNet as part of preparatory activities.			Short
See Sections 3.11 and 3.12 (VIC-SESA & SESA-CSA augmentations)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Sections 3.11 and 3.12 (VIC-SESA & SESA-CSA augmentations)		

80 This upgrade component has been flagged as a Network Capability Incentive Parameter Action Plan (NCIPAP) upgrade by ElectraNet and is treated as a committed project.

5.4.2 Riverland (S2)

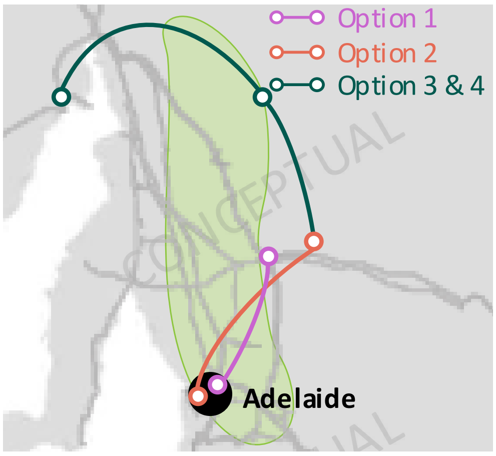
Summary	
The Riverland REZ is on the South Australian side of the proposed Project EnergyConnect route. It has good solar quality resources.	
Existing network capability	
There is minimal existing renewable generation in the zone. Prior to Project EnergyConnect, approximately 130 MW can be connected in this REZ for all three operating conditions (peak demand, summer typical and winter reference). Once Project EnergyConnect is commissioned, approximately 800 MW can be accommodated.	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Option 1 (Post PEC)[81]: • Co-ordinate new connections through turn in of Bundey – Buronga 330 kV No. 1 and No. 2 lines into a new substation at Riverland.	700	89	Class 5a (± 30%)	Short

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: no. of bays 6-10 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5a

[81] Additional REZ capacity will be reliant on additional circuits being connected to Bundey after Project EnergyConnect is complete.

5.4.3 Mid-North SA (S3)

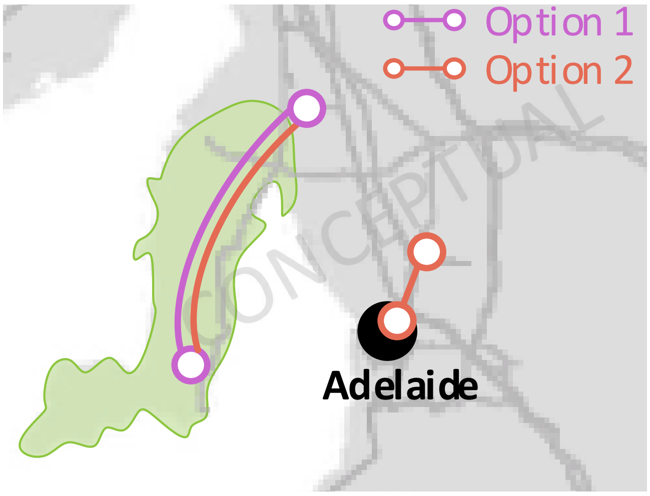
Summary	
The Mid-North SA REZ has moderate quality wind and solar resources. There are several major wind farms in service in this REZ, totalling > 950 MW installed capacity. Four 275 kV parallel circuits provide the bulk transmission along the corridor from Davenport to near Adelaide (Para) which traverse this REZ. This transmission corridor forms the backbone for exporting power from REZs north and west of this REZ in South Australia.	
Existing network capability The capability of this zone to accommodate new generation is subject to the MN1 mid-north group constraint[82].	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
See Section 4.4.11 (SA Group Constraints, MN1)				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
See Section 4.4.11 (SA Group Constraints, MN1)		

82 Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW.

5.4.4 Yorke Peninsula (S4)

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 subject to the MN1 mid-north group constraint[83].	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Option 1: • String first circuit of a 275 kV double-circuit line from Blythe West into new Yorke Peninsula substation. • Cut-in of Blythe West into Brinkworth-Templers West 275 kV line.	450	588	Class 5b (± 50%)	Medium
Option 2: • String second circuit of a 275 kV double-circuit line from Blythe West into new Yorke Peninsula substation. • Reinforce Templers West-Para 275 kV with 275 kV single-circuit line. *Pre-requisite: Option 1*	450	276	Class 5b (± 50%)	Long

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: 100 – 200 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote / Regional • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 100 – 200 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: None	• Known risks: BAU • Unknown risks: Class 5b

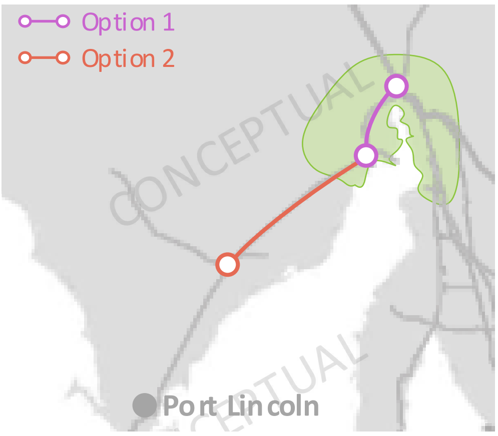
[83] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW.

	• Location (regional/distance factors): Remote / Regional • Delivery Timetable: Long	

5.4.5 Northern SA (S5)

Summary

The Northern SA REZ has good solar and moderate wind resources. This REZ forms a candidate for a hydrogen electrolyser facility in South Australia.



Existing network capability

The capability of this zone to accommodate new generation is subject to the MN1 mid-north and NSA1 northern group constraint[84].

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.4.11 (SA Group Constraints, NSA1)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.4.11 (SA Group Constraints, NSA1)		

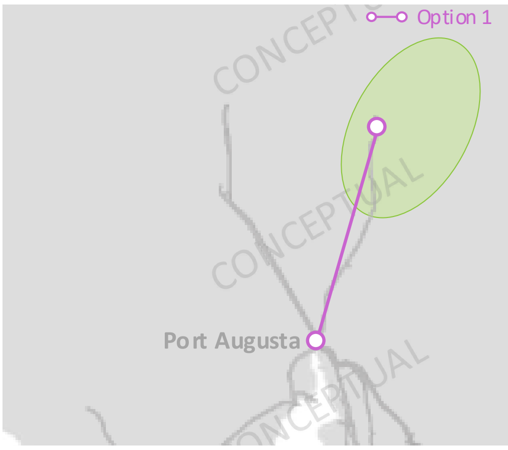
[84] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW or in Eyre Peninsula when S5, S8, S9 > 500 MW.

5.4.6 Leigh Creek (S6)

Summary

The Leigh Creek REZ is located between 150 and 350 km north-east of Davenport. It has excellent solar resources and good wind resources.

This REZ is currently supplied with a single 132 kV line.



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 group constraint[85].

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build 275 kV double-circuit line from Davenport to new Leigh Creek substation.	950	785	Class 5b (± 50%)	Short

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Scrub / Grazing • Project network element size: Above 200 km, no. of bays 11 - 15 • Proportion of environmentally sensitive areas: 100% / None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b

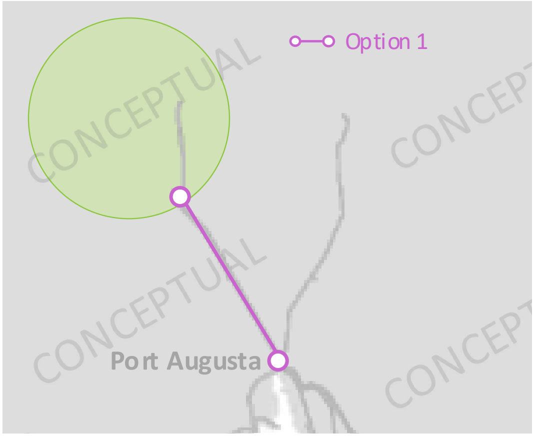
[85] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW.

5.4.7 Roxby Downs (S7)

Summary

The Roxby Downs REZ is located a few hundred kilometres north-west of Davenport. It has excellent solar resources. 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[86].

Augmentation options

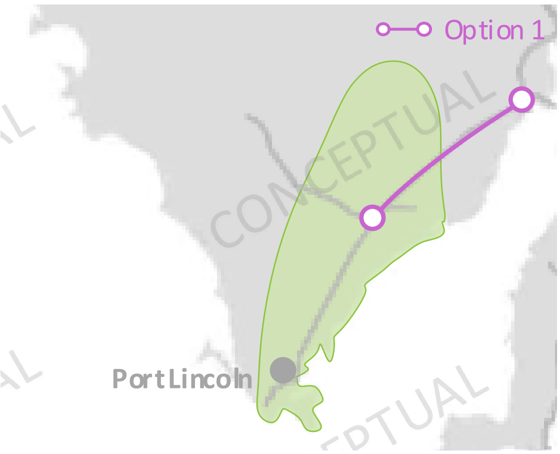
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build 275 kV double-circuit line from Davenport to new Roxby Downs substation.	950	526	Class 5b (± 50%)	Short

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Scrub / Grazing • Project network element size: 100 to 200 km, no. of bays 11 - 15 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b

[86] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW.

5.4.8 Eastern Eyre Peninsula (S8)

Summary	
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 will be built to operate at 275 kV, however initially energised at 132 kV.	
Existing network capability	
The existing network capacity of this REZ is 300 MW (subject to the capacity of the 275/132 kV transformers). The capability of this zone to accommodate new generation is subject to the MN1-SA mid-north and NSA1 northern group constraint[87].	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Option 1: • Operate the future Cultana Yadnarie 132 kV double-circuit line (built as part of the Eyre Peninsula Link RIT T) at 275 kV by establishing a 275 kV substation at Yadnarie.	300	64[88]	Class 5a (± 30%)	Short

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• To be updated in final 2023 *Transmission Expansion Options Report* based on ElectraNet feedback.	• To be updated in final 2023 *Transmission Expansion Options Report* based on ElectraNet feedback.

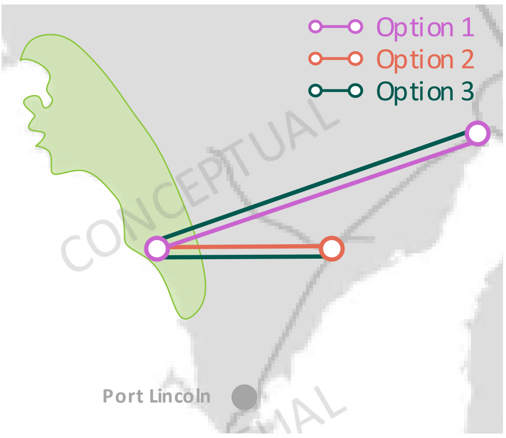
[87] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW or in Eyre Peninsula when S5, S8, S9 > 1,125 MW.

[88] AEMO is working to update this cost estimate based on ElectraNet feedback.

5.4.9 Western Eyre Peninsula (S9)

Summary

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-SA mid-north and NSA1 northern group constraint[89].

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 275 kV double-circuit line from Cultana/Corraberra Hill to a new Elliston substation.	950	826	Class 5b (± 50%)	Long
Option 2: • 275 kV single-circuit line from Yadnarie to a new Elliston substation.	500	411	Class 5b (± 50%)	Long
Option 3: • New Elliston substation. • Single-circuit 275 kV line from Cultana/Corraberra Hill to Elliston. • Single-circuit 275 kV line from Yadnarie to Elliston.	1,000	1,018	Class 5b (± 50%)	Long

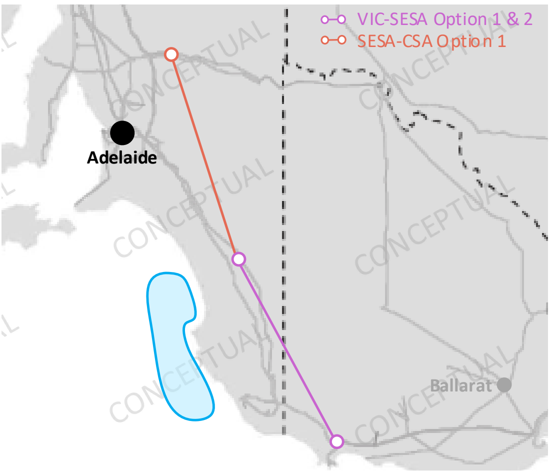
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: Above 200 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 100 to 200 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b

[89] Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >2,400 MW or in Eyre Peninsula when S5, S8, S9 > 1,125 MW.

Option 3	• Land use: Grazing • Project network element size: Above 200 km, no. of bays 16-20 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b

5.4.10 South East SA Coast (S10)

Summary	
The South East Coast REZ has been identified for the offshore wind resource potential in relatively shallow waters close to shore, with a connection point near to the South East SA. There is currently interest in this area of approximately 600 MW, but projects have not developed sufficiently at this stage to be considered anticipated.	
Existing network capability	
SA Coast REZ connects to an offshore collection node in the South East SA REZ. The network limit for this REZ is included as part of the SESA-CSA 650 MW sub-regional limit. There are no augmentation options specifically for this REZ. The associated augmentations are the VIC-SESA & SESA-CSA flow path augmentations (see Sections 3.11 and 3.12).	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Sections 3.11 and 3.12 (VIC-SESA & SESA-CSA augmentations)				

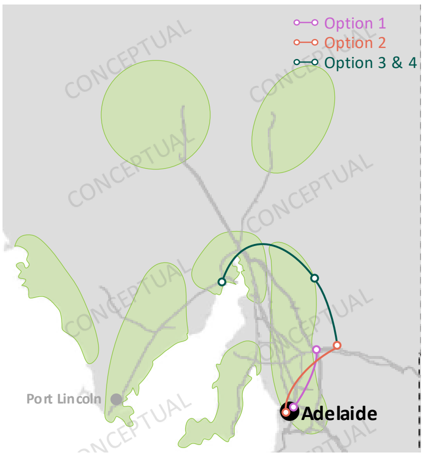
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Sections 3.11 and 3.12 (VIC-SESA & SESA-CSA augmentations)		

5.4.11 South Australia group constraints and transmission limit constraints

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 *Hydrogen Superpower* scenario.
Existing network capability
The individual REZs which form this group constraint each have their own individual existing network capabilities. The collective generation build from S3 to S9 cannot exceed 2,400 MW without additional network augmentation between Davenport and Adelaide.



Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Augmentation to alleviate the MN1 group constraint is linked to the S3 Mid-North REZ development				
S3 Option 1 (part of preparatory activities): • Build a 275 kV double-circuit line between Robertstown and Para[90].	To be completed by ElectraNet as part of preparatory activities.			Short
S3 Option 2[91]: Build a 330 kV double-circuit line from Bundey to Globe Derby.	1,000	670	Class 5b (± 50%)	Short
S3 Option 3: • Build a 275 kV double-circuit line from Bundey to Cultana. – Stage 1: 275 kV double-circuit from Bundey to a new substation near Yunta. – Stage 2: 275 kV double-circuit from a new substation near Yunta to Cultana.	800	1,301	Class 5b (± 50%)	Short
S3 Option 4: • Build a 330 kV double-circuit line from Bundey to Cultana.	1,000	1,301	Class 5b (± 50%)	Short

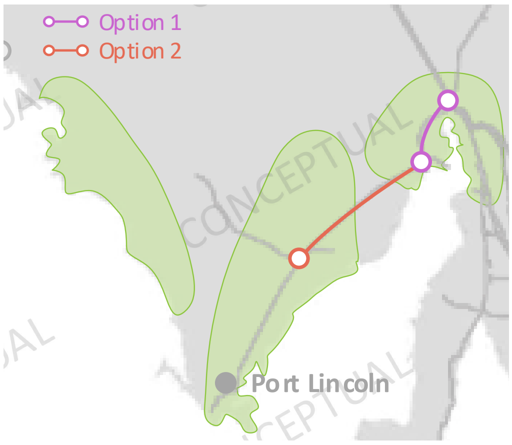
Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
S3 Option 1	To be completed by ElectraNet as part of preparatory activities.	
S3 Option 2	• Land use: Grazing / Developed Area • Project network element size: 100-200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Regional / Urban	• Known risks: BAU • Unknown risks: Class 5b

[90] Additional network hosting capacity is South of Robertstown towards Adelaide. This option does not alleviate the MN1 SA group constraint.

[91] AEMO is in consultation with ElectraNet to confirm augmentation scope and validate the network capacity benefit achieved from this option.

	• Delivery Timetable: Long	
S3 Option 3	• Land use: Grazing • Project network element size: Above 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b
S3 Option 4	As per Option 3	As per Option 3

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 Hydrogen Superpower scenario.	
Existing network capability	
The individual REZs which form this group constraint each have their own individual existing network capabilities. The collective generation build for S5, S8 and S9 cannot exceed 1125 MW without additional network augmentation between Davenport and Cultana.	

Augmentation options				
Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Augmentation to alleviate the NSA1 group constraint is linked to the S5 Northern SA and S8 Eastern Eyre Peninsula REZ developments.				
Option 1: • Build a 275 kV double-circuit line from Davenport-Cultana	1,200	229	Class 5b (± 50%)	Short
Option 2: • Operate the future Cultana Yadnarie 132 kV double-circuit line (built as part of the Eyre Peninsula Link RIT T) at 275 kV by establishing a 275 kV substation at Yadnarie. –	300	64[92]	Class 5a (± 30%)	Short

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Remote • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5b
Option 2	Cost estimate provided by ElectraNet.	• Cost estimate provided by ElectraNet.

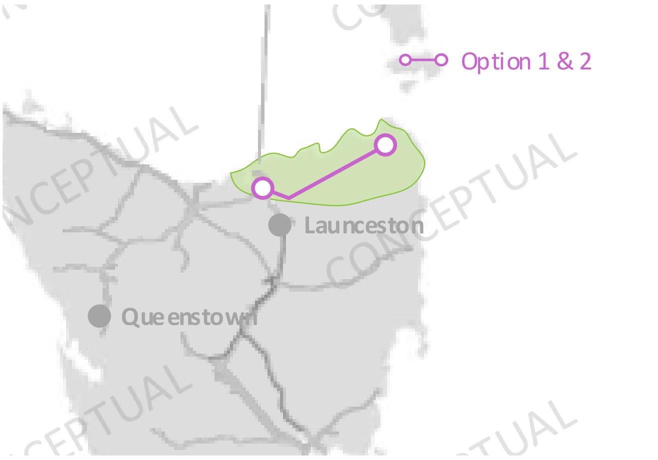
92 AEMO is working to update this cost estimate based on ElectraNet feedback.

5.5 Tasmania

5.5.1 North East Tasmania (T1)

Summary

This REZ has a good quality wind resources and moderate solar resources. North East Tasmania is distanced from the proposed Marinus Link augmentations and therefore upgrades are less influenced by the proposed new interconnector (see Section 4.10).



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[93].

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 220 kV double-circuit line between a new substation in George Town area, and a new substation in far north-east Tasmania.	800	350	Class 5b (± 50%)	Medium
Option 2: • Second 220 kV double-circuit line between the new substations in George Town and far north-east Tasmania, strung one side only. *Prerequisite: T1 Option 1*	800	252	Class 5b (± 50%)	Long

Adjustment factors and risk

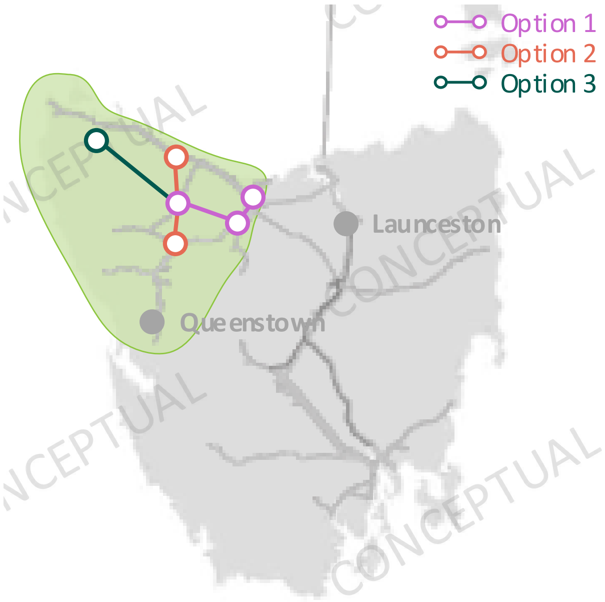
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 25% • Location: Regional, Urban • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location: Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5b

93 Additional augmentation is required in North East Tasmania when the combination of generation in T1 and T5 is greater than 1,600MW.

5.5.2 North West Tasmania (T2)

Summary

This REZ has excellent quality wind resources and good pumped hydro resources. The North West Tasmania augmentation options are highly dependent on Marinus Link, with some REZ network capacity increase already included in the proposed Marinus Link AC augmentations.



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. Note this REZ is affected by voltage 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)	Cost classification	Lead time
Option 1: Prior to (without) Marinus Link: • Build a new 220 kV switching station at Staverton and cut-in all Sheffield-Mersey Forth 220 kV lines at Staverton. • Build a new double-circuit Staverton-Hampshire Hills 220 kV line, and Hampshire Hills wind collector station. (note this is part of the TAS-VIC Option 1 augmentations). With Marinus Link: • Build new Hampshire Hills wind collector station.	800	239 (prior to (without) MarinusLink) / 25 (with MarinusLink)	Class 5a (± 30%)	Short
Option 2: • Build new "Farrell 2" wind collector station on west coast Tasmania (nearby existing Farrell substation) and establish new double-circuit Farrell2-Hampshire Hills 220 kV line. • Extend new Hampshire Hills-Burnie 220 kV double-circuit line. *Pre-requisite: TAS-VIC Option 2, T2 Option 1.*	800	355	Class 5a (± 30%)	Long
Option 3: • Build double-circuit West Montagu-Hampshire 220 kV line. *Pre-requisite: TAS-VIC Option 2, T2 Option 1.*	800	335	Class 5a (± 30%)	Medium

Adjustment factors and risk

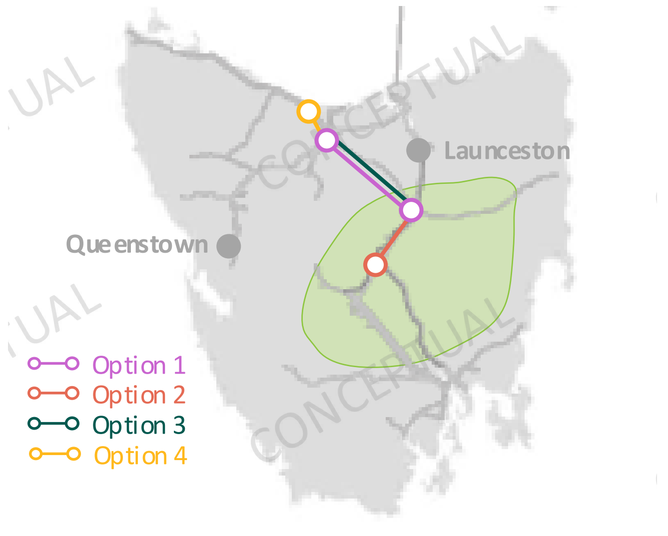
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Developed area, grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

Option 2	• Land use: Developed area, grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a
Option 3	• Land use: Developed Area, grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

5.5.3 Central Highlands (T3)

Summary

This REZ has excellent quality wind resources and has good pumped hydro resources. It is located close to major load centres at Hobart. The Tasmania Central Highlands augmentation options are influenced by the Marinus Link augmentations, with REZ network capacity increase already included in the proposed Marinus Link Palmerston to Sheffield 220 kV AC augmentations.



Existing network capability

The current total REZ transmission limit for existing (144 MW Wild Cattle Hill wind farm) and new VRE before any network upgrade in the Central Highlands is approximately 527 MW for peak demand and summer typical conditions and 668 MW for winter reference condition. VRE development opportunities are anticipated around the Waddamana substation.

Note that a runback scheme is not considered for any new transmission lines.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: Prior to (without) MarinusLink: • If before Marinus Link 1, bring forward the rebuild of Palmerston-Sheffield 220 kV line as double-circuit and build 2 x power flow controllers on the 2 x 220 kV transmission lines from Palmerston-Sheffield. With MarinusLink: • If after Marinus Link 1, build 2 x power flow controllers on the 2 x 220 kV transmission lines from Palmerton-Sheffield.	550	307 (prior to (without) MarinusLink) / 53 (after Marinus)	Class 5a (± 30%)	Short
Option 2[94]: • Build a Palmerston-Waddamana 220 kV double-circuit line. *Pre-requisite: TAS-VIC Option 1, T3 Option 1.*	375	151	Class 5a (± 30%)	Medium
Option 3: • Build a second Palmerston-Sheffield 220 kV double-circuit line. *Pre-requisite: TAS-VIC Option 2, T3 Option 2.*	675	257	Class 5a (± 30%)	Long
Option 4: • Build 2 x power-flow controllers on the 2 x 220 kV double-circuit transmission lines from Heybridge-Sheffield. *Pre-requisite: TAS-VIC Option 2, T3 Option 3.*	200	53	Class 5a (± 30%)	Medium

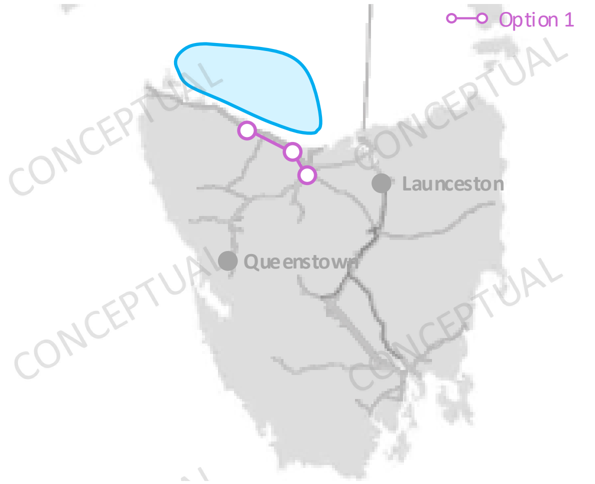
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing, developed area • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

[94] AEMO is continuing to consult with TasNetworks for utilisation and placement of power flow controllers to optimise flows for this option.

	• Delivery Timetable: Long	
Option 2	• Land use: Developed area, grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a
Option 3	As per Option 1	As per Option 1
Option 4	• Land use: Developed area • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: None • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

5.5.4 North West Tasmania Coast (T4)

Summary	
The North West 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. 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.	

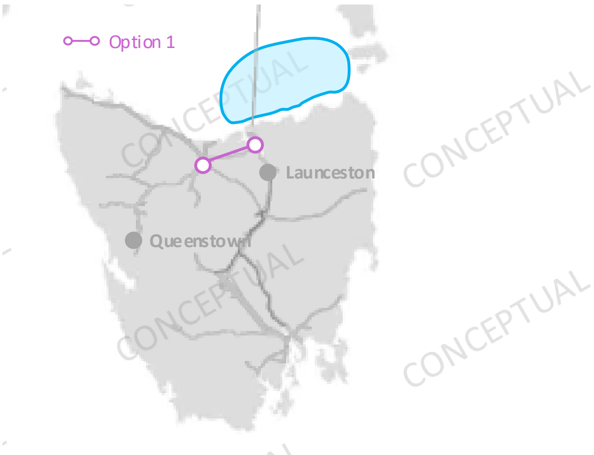
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build a new Burnie-Heybridge-Sheffield 220 kV double-circuit line. *Pre-requisites: TAS-VIC Option 2.*	1,360	193	Class 5a (± 30%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

5.5.5 North East Tasmania Coast (T5)

Summary	
Due to recent enquiries by offshore wind proponents around the North East Coast of Tasmania, the North East 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 George Town substation.	
Existing network capability	
North East Tasmania coast REZ connects to the 220 kV network within the North East REZ 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 1600 MW for offshore wind and onshore VRE from T1.	

Augmentation options

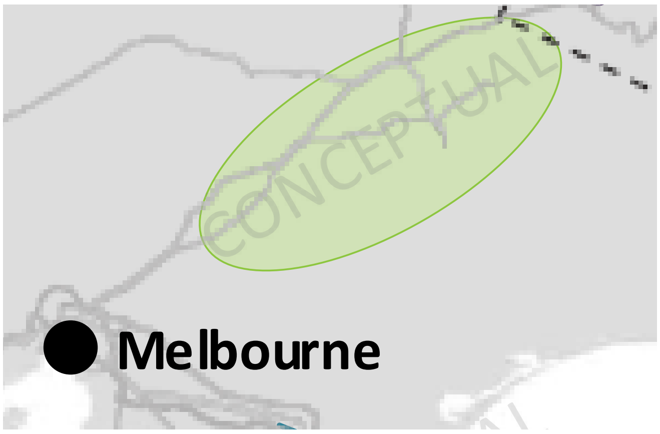
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build a new George Town-Sheffield 220 kV double-circuit line. • Build 2 x power flow controllers on the 2 x 220 kV double-circuit line between George Town-Hadspen. *Pre-requisite: TAS-VIC Option 2.*	900	287	Class 5a (± 30%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 km to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Environmental Offset Risk – High, Others - BAU • Unknown risks: Class 5a

5.6 Victoria

5.6.1 Ovens Murray (V1)

Summary	
The Ovens Murray REZ has been identified as a candidate REZ due to this REZ having good pumped hydro resources. There is currently 770 MW of installed hydro generation within this zone.	
Existing network capability	
The current network capacity in Ovens Murray is approximately 350 MW.	

Augmentation options

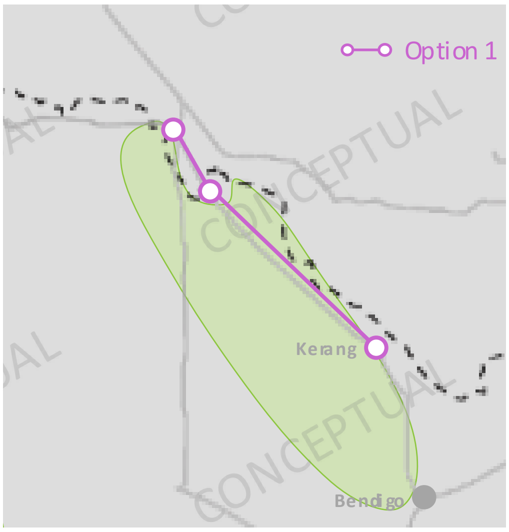
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
There are no associated augmentations with this REZ.				

5.6.2 Murray River (V2)

Summary

The Murray River REZ has good solar resources. Despite being remote and electrically weak, this REZ has attracted significant investment in solar generation. Voltage stability and thermal limits currently restrict the output of generators within this REZ.

The proposed VNI West project could 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 2022 *Victorian Annual Planning Report*, voltage oscillation constraints affecting this area will be reviewed after completion of the Western Renewables Link and Project EnergyConnect augmentations.



Existing network capability

The current REZ transmission limits for existing and new VRE before any network upgrade in Murray River is approximately 440 MW for peak demand & summer typical conditions and 640 MW for winter reference condition.

No additional capacity to connect new generation.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1:[95] • New 220 kV double-circuit line between Red Cliffs – Wemen – Kerang. • Establish new substations close to Redcliff and Kerang. Pre-requisite: VNI West (Bulgana)	800	894	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: Above 200 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings – BAU, Macroeconomic influence – BAU, Market activity – BAU, Weather delays – BAU, Project complexity - Highly complex, Compulsory acquisition – High, Environmental offset risks – High, Cultural heritage – High, Outage restrictions - BAU/High • Unknown risks: Class 5b

95 For the practicality of ISP modelling, AEMO has included this REZ option to enable increased generation connection interest near Kerang.

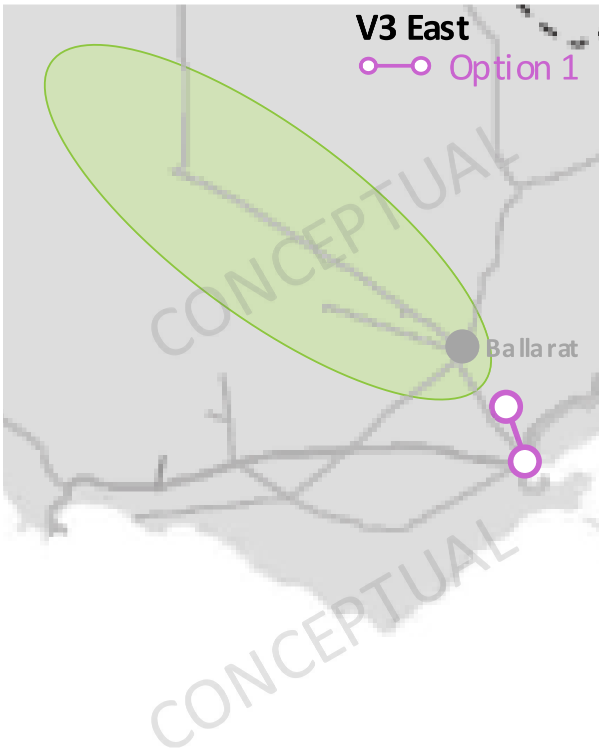
5.6.3 Western Victoria (V3)

Summary

The Western Victoria REZ has good to excellent quality wind resources. The existing and committed renewable generation within this REZ exceeds 1 GW, all of which is from wind generation. The current network is constrained west of Ballarat and cannot support any further connection of renewable generation without transmission augmentation.

The Western Renewables Link is an anticipated project, with the preferred option to expand generation within this zone.

REZ augmentation options shown take into account the change to the WRL scope as part of the VNI West RIT-T preferred option, and assumes 500 kV from Sydenham to Bulgana.



Existing network capability

The current REZ transmission limits for existing & new VRE before any network upgrade in Western Victoria is split between two modelling constraints:

<u>V3 East</u>

Approximately 600 MW for peak demand and summer typical conditions and 800 MW for winter reference condition

<u>V3 West</u>

Approximately 780 MW for peak demand and summer typical conditions and 980 MW for winter reference condition.

Network capacity is anticipated to be sufficient for existing and committed generation following completion of the Western Renewables Link.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
V3 East				
Option 1: New 220 kV single-circuit line from Elaine to Moorabool.	600	148	Class 5b (± 50%)	Medium
V3 West				
There are no associated augmentations with V3 West.				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
V3 East		
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Medium	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - High • Unknown risks: Class 5b

5.6.4 South West Victoria (V4)

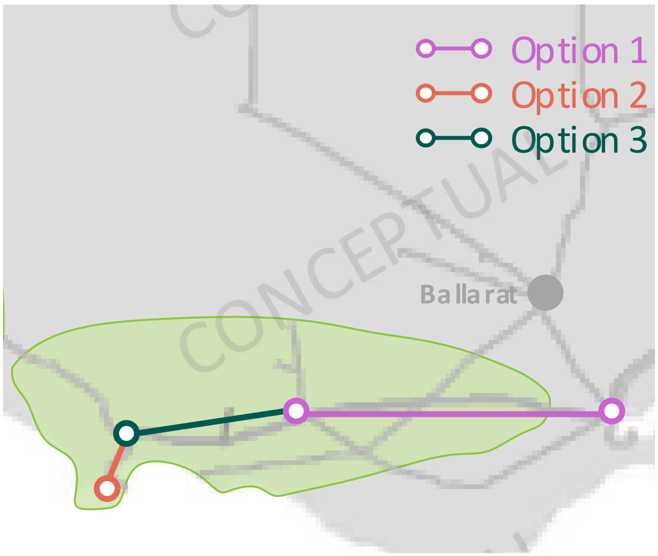
Summary

The South West Victoria REZ has moderate to good quality wind resources 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 2 GW.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The Government has announced that VicGrid will provide a coordinated transmission connection point near Portland[96].

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.



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 is modelled with the SWV1 group constraint.

This limit is approximately 1,700 MW for peak demand, summer typical and winter reference conditions, prior to commissioning of the Victorian Government RDP: Mortlake turn in Project[97]

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.5.9.1 (SWV1 group constraint augmentations)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.6.9 (SWV1 group constraint augmentations)		

[96] Victoria Government. Offshore wind energy. Implementation Statement 1. At https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

[97] RDP 1 – Stage 1: Mortlake turn in project, alleviates existing voltage constraint between Moorabool & Mortlake 500 kV Terminal Stations & 1500 MW of additional generation output. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf?la=en.

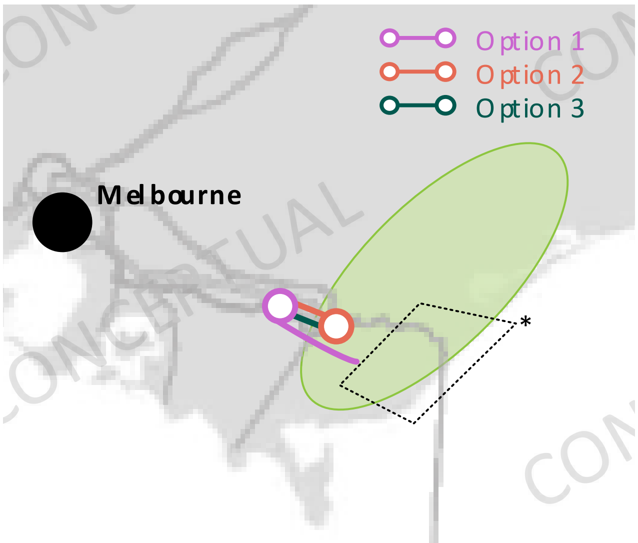
5.6.5 Gippsland (V5)

Summary

The Gippsland REZ has moderate quality wind resources, in proximity to the 500 kV networks. There is currently significant wind generation interest in this area.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The government has announced that VicGrid will provide a coordinated transmission connection point near the Gippsland Coast[98].

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.



* Coastal location of Option 1 is expected to be within the dotted box, as per the Victorian Offshore Wind Implementation Statement 1, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0030/603399/The-Victorian-Offshore-Wind-Implementation-Statement-1.pdf.

Existing network capability

Due to the strong network in this REZ (with multiple 500 kV and 220 kV lines from Latrobe Valley to Melbourne designed to transport energy from major Victorian brown coal power station), significant generation can be accommodated.

Approximately 6,000 MW of VRE, interconnector flow and output from other generation can be accommodated at the Hazelwood and Loy Yang 500 kV substations. This includes supply from existing generation, V5, V7 and TAS-VIC. This limit does not include the potential for connection of new generation at the Yallourn 220 kV substation. This limit is represented in the SEVIC1 REZ transmission limit equation.

AEMO Victorian Transmission Planning is exploring options for increasing this limit, for example through reconfiguring the arrangement of the 220 kV and 500 kV stations to ensure the existing Transmission lines are fully utilised and to support additional capacity.

Upgrade options are common with the Gippsland Coast REZ (V7).

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.6.9 (SEVIC1 group constraint augmentation options)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.6.9 (SEVIC1 group constraint augmentation options)		

98 Victoria Government. Offshore wind energy. Implementation Statement 1. At https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

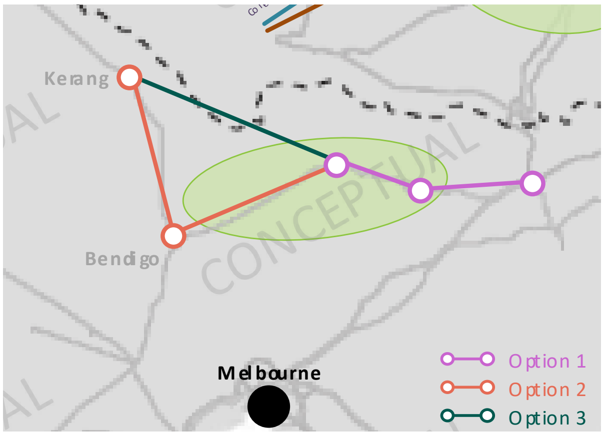
5.6.6 Central North Vic (V6)

Summary

The Central North Victoria REZ has moderate quality wind and solar resources. In addition to the currently in service and committed solar farms, there are enquires for approximately 2.5 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 & summer typical conditions & 1300 MW for the winter reference condition.



Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New double-circuit 220 kV line from Shepparton to Dederang via Glenrowan.	250	665	Class 5b (± 50%)	Long
Option 2: • New double-circuit 220 kV line from Shepparton – Near Bendigo – Near Kerang.	500	1,061	Class 5b (± 50%)	Long
Option 3: • New double-circuit 500 kV line from Shepparton – Near Kerang.	1,500	1,048	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 100 to 200 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - High • Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: Above 200 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - High, Outage restrictions – BAU Unknown risks: Class 5b
Option 3	• Land use: Grazing • Project network element size: 100 to 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - BAU • Unknown risks: Class 5b

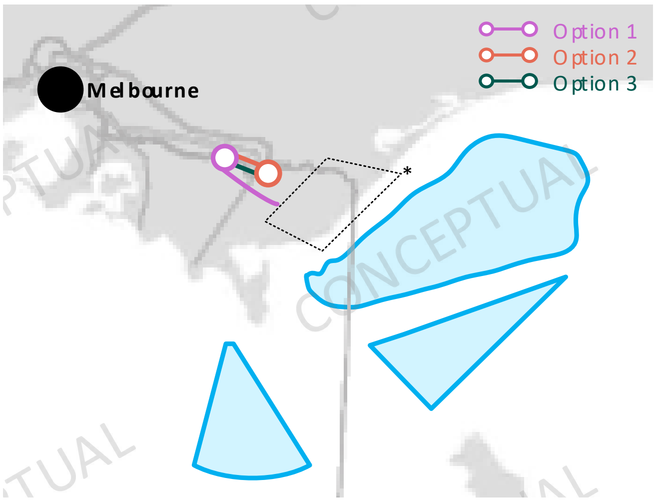
5.6.7 Gippsland Coast (V7)

Summary

The Gippsland Coast REZ has been identified for offshore wind resource potential in relatively shallow waters close to shore, with a connection point close to existing 500 kV networks at Loy Yang/Hazelwood. There is currently significant interest in this area from a number of offshore wind farms, but projects have not developed sufficiently at this stage to be considered anticipated.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The government has announced that VicGrid will provide a coordinated transmission connection point near the Gippsland Coast[99].

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.



* Coastal location of Option 1 is expected to be within the dotted box, as per the Victorian Offshore Wind Implementation Statement 1, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0030/603399/The-Victorian-Offshore-Wind-Implementation-Statement-1.pdf.

Existing network capability

Gippsland offshore REZ connects to the 500 kV network in the Gippsland REZ. See Section 4.6.5 for a description of existing network capability.

Upgrade options are common with the Gippsland REZ (V5).

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.6.9 (SEVIC1 group constraint augmentation options)				

Adjustment factors and risk

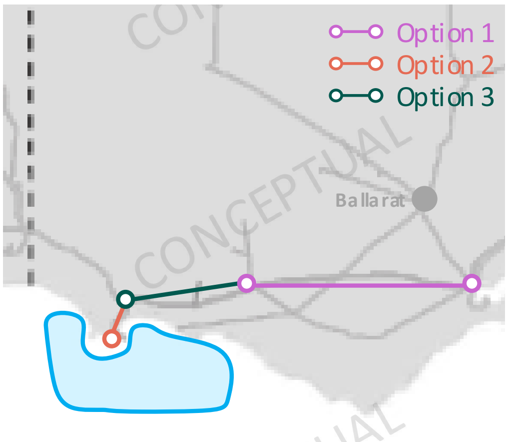
Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.6.9 (SEVIC1 group constraint augmentation options)		

[99] Victoria Government. Offshore wind energy. Implementation Statement 1. At https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

5.6.8 Portland Coast (V8)

<table>
<tr><th colspan="6">Summary</th></tr>
<tr><td colspan="3">The Portland Coast REZ has been identified for offshore wind resource potential in relatively shallow waters close to shore, with a connection point close to existing 500 kV networks at APD/Heywood.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The government has announced that VicGrid will provide a coordinated transmission connection point near Portland[100].

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.</td><td colspan="3" rowspan="4">
</td></tr>
<tr><th colspan="3">Existing network capability</th></tr>
<tr><td colspan="3">The network capacity available for V8 is the same as V4 South West Victoria. REZ augmentation options are common to those shown for V4 & SWV1.</td></tr>
<tr></tr>
<tr><th colspan="6">Augmentation options</th></tr>
<tr><th colspan="2">Description</th><th>Additional network capacity (MW)</th><th>Expected cost ($ million)</th><th>Cost classification</th><th>Lead time</th></tr>
<tr><td colspan="6">See Section 4.6.9 (SWV1 group constraint augmentations)</td></tr>
<tr><th colspan="6">Adjustment factors and risk</th></tr>
<tr><th>Option</th><th colspan="2">Adjustment factors applied</th><th colspan="3">Known and unknown risks applied</th></tr>
<tr><td colspan="6">See Section 4.6.9 (SWV1 group constraint augmentations)</td></tr>
</table>

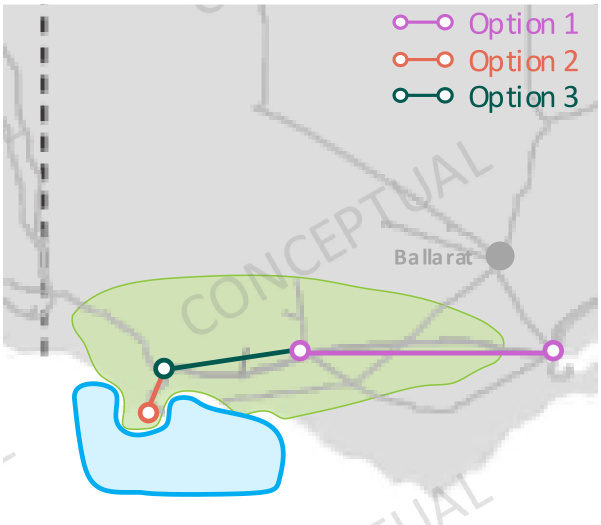
[100] Victoria Government. Offshore wind energy. Implementation Statement 1. At https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

5.6.9 Victoria group constraints and transmission limit constraints

SWV1

Summary

The group constraint SWV1 represents the generation build limit applied to V4, V8 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.



Existing network capability

The network capacity available for SWV1 is the same as for V4 South West Victoria and V8 Portland Coast. REZ augmentation options are common to those shown for V4.

Under the ISP preparatory activities function, AEMO Victoria Planning is considering additional options across SWV1. Outcomes from the preparatory activity works will be incorporated into the final 2023 Transmission Expansion Options Report.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 500 kV single-circuit line from Mortlake – Moorabool. *Pre-requisite: Mortlake turn-in*[101]	1,000	830	Class 5b (± 50%)	Long
Option 2: • New 500 kV single-circuit line between Heywood and APD *Pre-requisite: Mortlake turn-in*	1,400	255	Class 5b (± 50%)	Long
Option 3: • New 500 kV single-circuit line between Heywood and Mortlake. *Pre-requisite: Mortlake turn-in*	2,500	547	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 100 to 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - BAU • Unknown risks: Class 5b
Option 2	• Land use: Grazing / Developed Area • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 50%	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - High/BAU

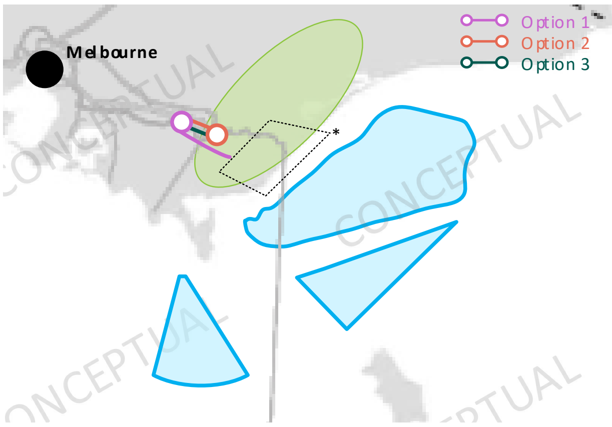
101

	• Location (regional/distance factors): Regional / Urban • Delivery Timetable: Long	• Unknown risks: Class 5b
Option 3	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - BAU, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - BAU • Unknown risks: Class 5b

SEVIC1

Summary

The group constraint SEVIC1 represents the generation build limit applied to V5, V7 REZs and the TAS-VIC 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.



* Coastal location of Option 1 is expected to be within the dotted box, as per the Victorian Offshore Wind Implementation Statement 1.

Existing network capability

The network capacity available for SEVIC1 is the same for V5 Gippsland & V7 Gippsland Coast. REZ augmentation options are common to those shown for V5 and V7.

Approximately 6,000 MW of VRE, interconnector flow and output from other generation can be accommodated at the Hazelwood and Loy Yang 500 kV substations. This includes supply from existing generation, V5, V7 and TAS-VIC. This limit does not include the potential for connection of new generation at the Yallourn 220 kV substation. This limit is represented in the SEVIC1 REZ transmission limit equation.

AEMO Victorian Transmission Planning is exploring options for increasing this limit, for example through reconfiguring the arrangement of the 220 kV and 500 kV stations to ensure the existing Transmission lines are fully utilised and to support additional capacity.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 500 kV double-circuit line from Hazelwood to vicinity of Gippsland coast. • Two 500/220 kV transformers. • 250 MVAr dynamic reactive compensation	2,000	852	Class 5b (± 50%)	Long
Option 2: • New 500 kV double-circuit line from Hazelwood to Loy Yang • 250 MVAr dynamic reactive compensation	2,000	520	Class 5b (± 50%)	Long
Option 3: • Another New 500 kV double-circuit line from Hazelwood to Loy Yang • 250 MVAr dynamic reactive compensation *Pre-requisite: V5 Option 3*	2,000	520	Class 5b (± 50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High, Environmental offset risks - High, Cultural heritage - High, Outage restrictions - High Unknown risks: Class 5b
Option 2	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 11-15	• Known risks: Geotechnical findings - BAU, Macroeconomic influence - BAU, Market activity - BAU, Weather delays - BAU, Project complexity - Highly complex, Compulsory acquisition - High,

	• Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	Environmental offset risks - High, Cultural heritage - High, Outage restrictions - High/BAU Unknown risks: Class 5b
Option 3	As per Option 2	As per Option 2

6 Generation 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.

This section outlines:

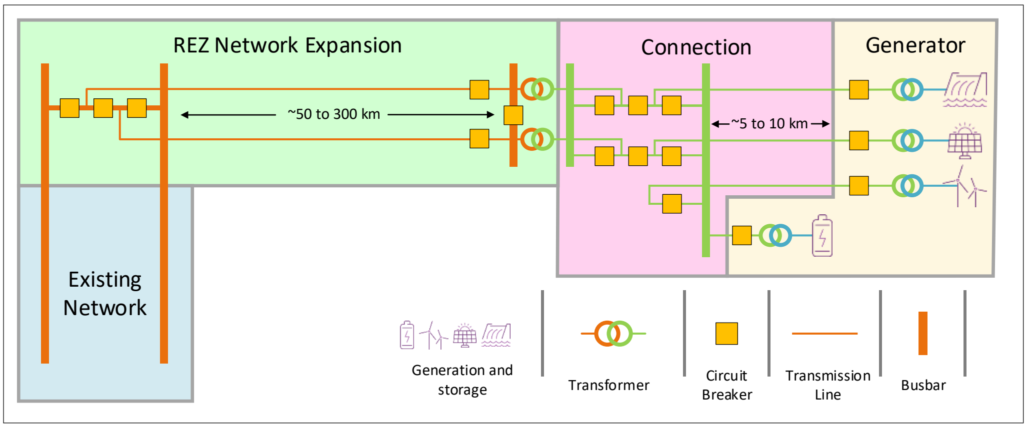
- Generator connection costs (Section 6.1).
- Treatment of system strength costs for the ISP (Section 6.2).
- Offshore REZ connection costs (Section 6.3).

6.1 Generator 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 11 illustrates how connection costs are defined in relation to the REZ network expansion costs.

Figure 11 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. 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 variable renewable energy (VRE).

Table 7 describes the parameters of the connection assets used for solar and wind generation connecting in each REZ. Table 8 describes parameters for other generation technologies which are close to the network. Table 9 describes parameters for batteries which require no feeder.

Table 7 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	47	67.47
North Queensland Clean Energy Hub	QLD	275	300	10	33	112.60
Northern Queensland	QLD	275	300	5	31	67.47
Isaac	QLD	275	300	5	42	59.79
Barcaldine	QLD	275	300	10	31	97.24
Fitzroy	QLD	275	300	5	31	59.79
Wide Bay	QLD	275	300	5	31	59.79
Darling Downs	QLD	275	300	5	606	59.79
Banana	QLD	275	1,000	200	50	603.50
North West New South Wales	NSW	330	400	10	50	93.94
New England	NSW	330	400	10	50	93.94
Central-West Orana	NSW	330	400	10	41	93.94
Broken Hill	NSW	220	250	10	51	112.14
South West New South Wales	NSW	330	400	10	51	95.11
Wagga Wagga	NSW	330	400	10	37	95.11
Tumut	NSW	330	400	5	37	60.33
Cooma-Monaro	NSW	330	400	5	24	60.33
Hunter-Central Coast	NSW	330	400	5	NA*	60.33
Hunter Coast	NSW	NA*	NA*	NA*	NA*	NA*
Illawarra Coast	NSW	NA*	NA*	NA*	24	NA*
Illawarra	NSW	330	400	5	32	60.33
Ovens Murray	VIC	220	250	5	31	76.07
Murray River	VIC	220	250	5	33	71.06
Western Victoria	VIC	220	250	5	71	81.07
South West Victoria	VIC	500 & 220	600	10	46	118.17
Gippsland	VIC	220	250	10	43	130.61
Central North Victoria	VIC	220	250	10	741	122.15
Gippsland Coast	VIC	500	1,200	0	NA*	604.19
Portland Coast	VIC	NA*	NA*	NA*	42	NA*
South East South Australia	SA	275	300	10	47	97.94
Riverland	SA	275	300	10	34	112.53
Mid-North South Australia	SA	275	300	5	34	69.90
Yorke Peninsula	SA	275	300	5	43	69.90
Northern South Australia	SA	275	300	10	43	100.72
Leigh Creek	SA	275	300	10	41	100.72
Roxby Downs	SA	275	300	10	41	93.77

REZ names	Region	REZ network voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($ million)	Cost ($/kW)
Eastern Eyre Peninsula	SA	275	300	10	41	93.77
Western Eyre Peninsula	SA	275	300	10	836	93.77
South East South Australia Coast	SA	275	1,200	50	39	686.67
North East Tasmania	TAS	220	150	5	34	172.03
North West Tasmania	TAS	220	150	5	31	140.50
Central Highlands	TAS	220	150	5	NA*	122.54
North West Tasmania Coast	TAS	NA*	NA*	NA*	NA*	NA*
North East Tasmania Coast	TAS	NA*	NA*	NA*	33	NA*
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		

Table 8 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	53	88.39
330	400	1	24	59.55
275	300	1	23	75.71
220	250	1	22	87.68
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	

Note: Connection costs for pumped hydro and offshore wind are included in the generation cost.

Table 9 Connection costs for batteries

Connection voltage (kV)	Connection capacity (MVA)	Total cost ($ million)	Cost ($/kW)
500	600	48	79.47
330	400	20	50.55
275	300	20	65.35
220	250	19	75.92
Adjustment factors and risk			
All options	• Project network element size: no. of total Bays 1-5	• Known risks: BAU • Unknown risks: Class 5	

Consultation questions

7. Do you agree with the proposed cost estimation process and outcomes for generator connections in the ISP? If not, why not? Please provide evidence to support your feedback.

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 system strength service cost estimates in the ISP to estimate the requirement to support stable operation of IBR in the NEM, consistent with the system strength standard[102].

Synchronous condenser costs are used to derive a proxy cost for potential system strength remediation solutions. 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 $2 million cost.

Table 10 System strength services cost options

Description	Expected cost ($ million)	Cost classification	Lead time
80 MVA synchronous condenser	66.5	Class 5b (±50%)	Medium
125 MVA synchronous condenser	89.5	Class 5b (±50%)	Medium
200 MVA synchronous condenser	123.3	Class 5b (±50%)	Medium
250 MVA synchronous condenser	170.0	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	

Consultation questions

8. Do you agree with the proposed cost estimation process and outcomes for system strength costs for generator connections in the ISP? If not, why not? Please provide evidence to support your feedback.

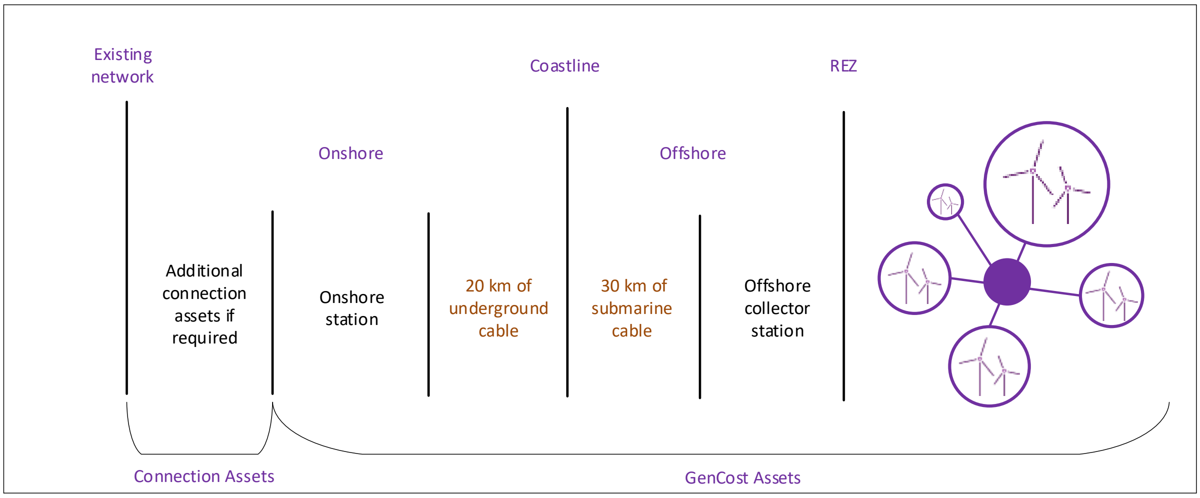
102 This does not include the minimum fault level requirement element of the system strength standard.

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 12 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 expansion option, as it is dedicated to connecting to offshore generation.

Figure 12 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 costs for these offshore REZs is zero.

For other coastal REZs, like S10 South East SA Coast and V7 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 Expansion option. For these two REZs, the cost of additional transmission has been included as a connection cost.

Consultation questions

9. Do you agree with the proposed cost estimation process and outcomes for offshore REZ connections in the ISP? If not, why not? Please provide evidence to support your feedback.

A1. Cost classification checklist

The checklist developed by AEMO for review of the TNSP estimates is shown below.

Class sub-category	Class 5		Class 4	Class 3	Class 2/1
	'b'	'a'			
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
Has 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

Class sub-category	Class 5 'b'	Class 5 'a'	Class 4	Class 3	Class 2/1
Project management and delivery					
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
Has geotechnical findings been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has outage restrictions been factored into the assessment of risk?	Yes	Yes	Yes	Yes	Yes
Has 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