2021 Transmission Cost Report

August 2021

Final report

For the Integrated System Plan (ISP)

Important notice

PURPOSE

AEMO publishes this *2021 Transmission Cost Report* as part of an initiative to improve the accuracy and transparency of transmission costs used for the *2022 ISP*. This report supplements the final *2021 Inputs, Assumptions and Scenarios Report (IASR)*.

DISCLAIMER

AEMO has made all reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market (NEM) might require, and does not amount to a recommendation of any investment.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2021	Initial release
1.1	6/8/2021	Minor correction to AEMO's review of TNSP cost estimates presented in Table 9

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1. Introduction

AEMO's *Integrated System Plan* (ISP) is a whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years.

AEMO considers that leveraging expertise from across the industry is pivotal to the development of a robust plan that supports the long-term interests of energy consumers. As part of the 2022 ISP development process, AEMO is focusing on improving transparency and stakeholder engagement on a range of areas, including improving transmission cost estimation. Accurate cost estimates are a vital component of the process to determine whether transmission projects should proceed.

In preparing this *2021 Transmission Cost Report*, AEMO has endeavoured to address all stakeholders needs in the establishment of a framework to provide a transparent and standardised approach to estimation of costs for ISP transmission projects, together with associated public release of all information used by the ISP for estimates for future transmission. The resulting *2021 Transmission Cost Report* and associated public database release are world-leading initiatives in transparency for regulated transmission builds.

This *2021 Transmission Cost Report* forms part of the *2021 Inputs, Assumptions and Scenarios Report* (IASR). It describes the engagement of independent experts and provision of industry advice, culminating in publishing the final report, which presents a summary of the design, capacity and cost estimate for candidate transmission projects for the 2022 ISP. As part of the actionable ISP rules, AEMO has asked transmission network service providers (TNSPs) to provide detailed estimates for some projects (see Section 1.1).

A four-week consultation was held on the *Draft Transmission Cost Report*, and feedback from stakeholders has been incorporated into this final report. Responses to the consultation are included in the *IASR Consultation Summary Report*[1].

Cost estimation accuracy

The Australian Energy Regulator's (AER's) *ISP Guidelines*[2], *Regulatory Investment Test for Transmission (RIT-T) Application Guidelines*[3] and its guidance note on the regulation of large transmission projects[4] do not prescribe the class or accuracy level of cost estimates throughout the ISP, RIT-T and Contingent Project Application (CPA) process.

Based on feedback received to the transmission cost consultation, it is clear that there is a range of conflicting expectations on the appropriate level of cost estimate accuracy within these frameworks.

AEMO acknowledges the proposed 'Material Change in Network Infrastructure Project Costs Rule Change'[5], that has not yet been initiated by the Australian Energy Market Commission (AEMC), and expects this will provide a platform for ongoing discussion on the matter of cost estimation accuracy. Currently, TNSPs have discretion on whether to re-apply the RIT-T if costs change after completion. The rule change proposal

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[1] AEMO. *2021 IASR Consultation Summary Report*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[2] AER. *Guidelines to make the ISP actionable*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable.

[3] AER. *RIT-T Application Guidelines*, at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf.

[4] AER. *Regulation of large transmission projects*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects.

[5] AEMC. *Material change in network infrastructure project costs*, at https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs.

requests that the AER becomes the determining authority for the requirement to re-apply the RIT if a cost increase after the RIT-T exceeds a certain threshold.

Supplementary materials

Table 1 below outlines related files and reports that have been used to determine transmission costs for the 2022 ISP. Stakeholders are invited to refer to these documents for further background and context.

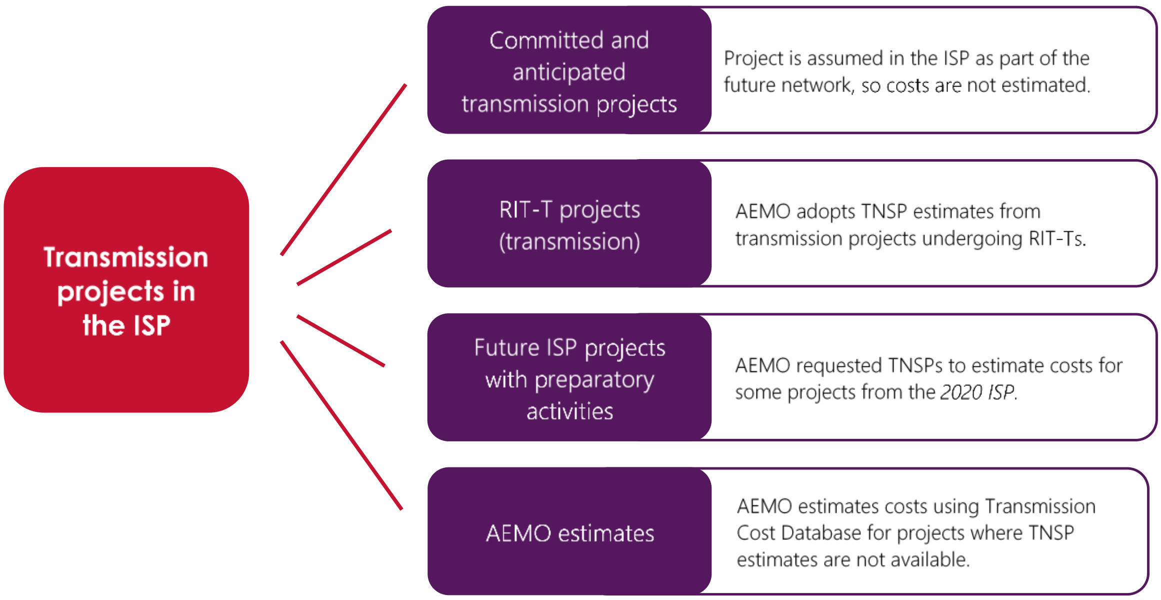
Table 1 Related files and reports

Document	Description	Location
2021 IASR	Description of all inputs, assumptions and scenarios used in the *2022 ISP* modelling.	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
IASR Consultation Summary Report	Responses to the stakeholder submissions to consultations on the Draft IASR and Draft Transmission Cost Report	
Transmission Cost Database	Database of cost estimate inputs and cost estimating tool used for Future ISP projects.	
Transmission Cost Database User Manual	Describes how to use the *Transmission Cost Database*.	
Transmission Cost Database Consultant's Report	Report documenting the construction and benchmarking of the *Transmission Cost Database*.	
Transmission Cost Estimate Calculations	A compressed ZIP file containing *Transmission Cost Database* output files for each project option. These records show the makeup of AEMO's transmission cost estimates – including building blocks, adjustments, risk and indirect costs.	

1.1 Application of transmission cost estimates in the ISP

AEMO's approach to incorporating cost estimates in the ISP is illustrated in Figure 1 below.

Figure 1 AEMO's approach to incorporating transmission projects in the IASR



TNSPs were asked to provide estimates and initial designs for "Future ISP projects with Preparatory Activities" or projects undergoing the RIT-T process. AEMO cross-checked this information using the Transmission Cost Database before including it in the final 2021 IASR.

All other projects not costed by TNSPs were estimated by AEMO using the new Transmission Cost Database. The Transmission Cost Database provides suitable risk margins at the early stages of a proposed project to allow for the large amount of known but as yet unquantified risks, and potential additional costs (currently unknown) that may arise in later stages of a proposed project.

Committed and anticipated projects

The *CBA Guidelines* (and the RIT-T Instrument[6]) define five criteria that must be used to assess the commitment status of projects:

- If the project has satisfied all five criteria, it is defined as a committed project.
- If the project is in the process of meeting at least three of the criteria, it is defined as an anticipated project.

AEMO includes all committed and anticipated projects in all future states of the world, in accordance with the AER's *CBA Guidelines*[7]. Because these projects are assumed to proceed, the project cost is not considered in the ISP.

The projects in Table 2 are classified as committed or anticipated transmission projects.

Table 2 Committed and anticipated transmission projects for the 2022 ISP

Project	Status	Responsible TNSP(s)	More information
Central West Orana REZ Transmission Link	Anticipated †	TransGrid	https://energy.nsw.gov.au/renewables/renewable-energy-zones; Section 4.2.3 of this report.
Eyre Peninsula Link	Committed	ElectraNet	https://www.electranet.com.au/projects/eyre-peninsula-link/
Northern QREZ Stage 1	Anticipated	Powerlink	https://www.powerlink.com.au/queensland-renewable-energy-zones
Project EnergyConnect	Anticipated ‡	ElectraNet and TransGrid	https://www.projectenergyconnect.com.au/
Queensland to New South Wales Interconnector (QNI) Minor	Committed	Powerlink and TransGrid	https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity; https://www.transgrid.com.au/qni
Victoria to New South Wales Interconnector (VNI) Minor	Committed	AEMO (Victorian TNSP) and TransGrid	https://www.transgrid.com.au/vni; https://aemo.com.au/en/initiatives/major-programs/victoria-to-new-south-wales-interconnector-upgrade-regulatory-investment-test-for-transmission
VNI System Integrity Protection Scheme (SIPS)	Committed	AEMO (Victorian TNSP)	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf
Western Victoria Transmission Network Project	Anticipated	AEMO (Victorian TNSP)	https://www.westvictnp.com.au/

† The Central West Orana REZ Transmission Link is currently at an advanced stage of consultation and planning, and is expected to be shovel-ready by the end of 2022. Following the legislation of the *NSW Electricity Infrastructure Investment Act*, this is now considered to be an anticipated project for the purpose of the 2022 ISP.
‡ Project EnergyConnect was approved by the AER on 31 May 2021.

6 See https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

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

RIT-T cost estimates

AEMO requested cost estimates and augmentation information from TNSPs for projects currently being assessed under the RIT-T. 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 TNSPs are best placed to estimate the cost of these projects. To ensure consistency across regions, AEMO reserved the right to add offsets to prices advised by TNSPs to ensure uncertainty and risks are applied consistently across investment options. Estimates for costs for HumeLink and the New South Wales works on Victoria to New South Wales Interconnector (VNI) West are included using TransGrid's estimates. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

Table 3 RIT-T projects in the ISP

Project	Responsible TNSP	Section in this report
HumeLink	TransGrid	Section 3.8
Improving stability in south-western New South Wales	TransGrid	Section 4.2.5
Marinus Link	TasNetworks	Section 3.10
VNI West	AEMO (Victorian TNSP) and TransGrid	Section 3.9

Preparatory activities

As part of the actionable ISP rules, AEMO asked TNSPs to provide a report on preparatory activities for future ISP projects. These are transmission projects that may become actionable ISP projects, but about which more detailed information – such as improved cost estimates, network designs, and initial appraisal of land considerations – is required.

Please note that preparatory activities are not the same as early works. Preparatory activities are needed to design and to investigate the costs of actionable ISP projects and future ISP projects. Early works are higher cost, and can include critical path investments which are needed to commence construction, such as easement acquisition or acquiring a slot in a manufacturer's queue for long lead time equipment.

Further, the initial high-level design and costing provided in a preparatory activities report is approximate, because detailed requirements for robust costings and plant design have not been undertaken. This would require much more extensive work, including detailed geotechnical land surveying and engagement on the route and necessary planning approvals.

In the 2020 ISP, AEMO triggered preparatory activities for Powerlink and TransGrid:

- Powerlink's preparatory activities reports are available on AEMO's website[8], and are summarised throughout this report.
- Although TransGrid provided AEMO with preparatory activities reports, the costs were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

The projects for which preparatory activities were triggered for TNSPs are outlined in the following table.

[8] AEMO. *Transmission costs for the 2022 Integrated System Plan*, at https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

Table 4 Preparatory activities

Project	2020 ISP Timing	Preparatory activities were required by	Responsible TNSP(s)	Section(s) in this report
Gladstone Grid Reinforcement	2030s	30 June 2021	Powerlink	Section 3.3
Central to Southern Queensland Transmission Link	Early 2030s	30 June 2021	Powerlink	Section 3.4
QNI Medium and Large	2032-33 to 2035-36	30 June 2021	Powerlink and TransGrid†	Sections 3.5 and 3.6
Reinforcing Sydney, Newcastle and Wollongong Supply	2026-27 to 2032-33	30 June 2021	TransGrid†	Section 3.7
North West NSW REZ Network Expansion	2030s, based on connection interest	30 June 2021	TransGrid†	Section 4.2.1
New England REZ Network Expansion	2030s	30 June 2021	TransGrid†	Section 4.2.2

† AEMO developed independent cost estimates for the NSW components of these projects because TransGrid's cost estimates were provided on a confidential basis.

AEMO's cost estimates

There are many transmission projects assessed in the ISP where TNSPs have not developed augmentation options and cost estimates. For these projects, AEMO determines and consults on augmentation options and cost estimates. This process started in December 2020, where AEMO consulted on augmentation corridors in the *Draft 2021 IASR*[9].

This final report outlines options to augment these corridors. The augmentation options are split into two main groups:

- **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 2.7.
- **REZs** – the network required to connect renewable generation in areas where clusters of large-scale renewable energy can be developed using economies of scale – see Section 4.

[9] At https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

2. Methodology

In response to feedback from stakeholders, AEMO initiated a work program after the 2020 ISP to improve the transparency and robustness of the transmission cost estimation process used for subsequent ISPs. This included an update to the cost estimation methodology that enhances the approach for incorporating risk, and preparation of 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 describes the following aspects:

- The development stages of cost estimates, which become more detailed and accurate as a project progresses.
- The Transmission Cost Database – used for AEMO estimates.
- TNSP estimates, which describes how AEMO reviewed estimates from TNSPs to ensure consistency and appropriateness for the ISP.

2.1 Cost estimate development stages

It should be noted that this section is intended to provide a high-level description of the complex process that is used to develop transmission projects over many years, and relevant generic background on the nature of cost estimation, to aid stakeholder understanding and increase transparency of the development process. The content represents AEMO's understanding of the typical stages of project development and estimation used by Australian TNSPs, noting that this will vary for individual TNSPs. The content is not prescriptive, and stakeholders are referred to the AER RIT-T guidelines for more information[10].

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 over years (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. 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.

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 as the starting point for its cost estimate methodology to classify cost estimates, and refined it to reflect the Australian electricity sector regulatory framework.

In response to stakeholder feedback, AEMO has also introduced an additional stage within Class 5 to better reflect the range of estimates and accuracies that are available within the Australian regulated electricity sector. These are defined as follows:

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

Table 5 Class 5 estimate sub-categories

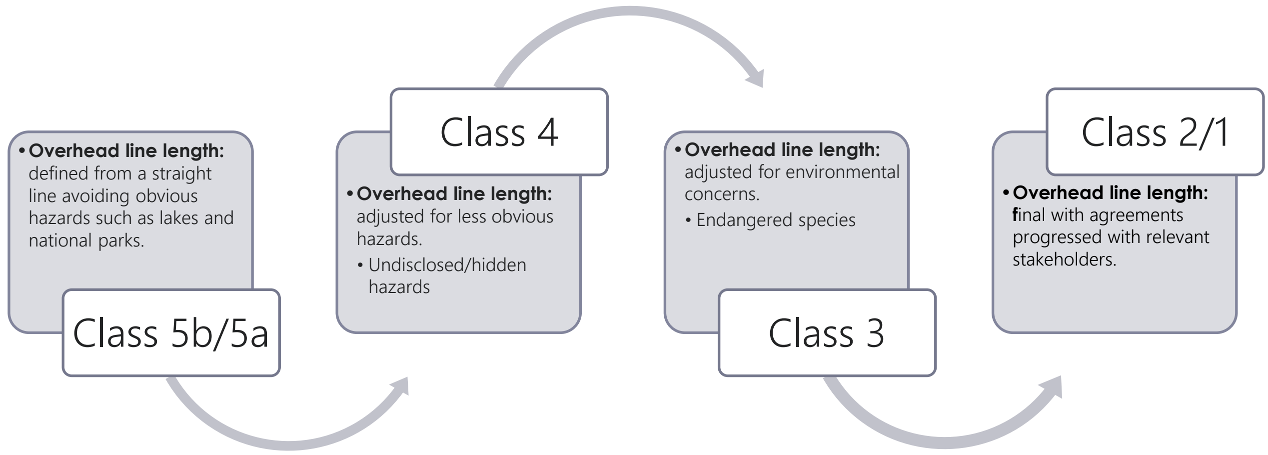
Class	Definition
Class 5b	Concept level scoping with no site-specific review or TNSP input
Class 5a	Screening level scoping including high level site-specific review and TNSP input

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

Figure 2 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 2 Design progress with project maturity – example showing how overhead line length assumption changes



Application to the ISP

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

Table 6 shows the current stages for ISP projects and outlines the planning and development works that typically take place at each stage. The table illustrates the ISP regulatory process; the Future ISP projects are estimated by AEMO, and the other stages 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 stage, which may vary across the TNSPs and across projects. AER guidelines[11] 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 stage will depend on the nature of the project.

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

Table 6 Indicative ISP project development stages

Stage	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) †
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, taking into account submissions received on Project Specification Consultation Report (PSCR – if under previous ISP rules)	• 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/supplier s may be sought • Desktop geotechnical/ ecology/heritage/ planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Stakeholder engagement plan developed • Credible alignment path identified, avoiding significant known risks and environmental sensitivities • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Technical specifications refined, relevant network studies substantially complete • Concept tower and substation design further refined • For significant projects a non-committal budget (guide) estimate from appropriate contractors/suppliers may be sought • Desktop geotechnical/ ecology/heritage/ planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Credible network option identified based on Geotech/ ecology/heritage/lan d tenure desktop planning and network studies • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Technical specifications completed • For significant projects a non-committal budget (guide) estimate from appropriate contractors/suppl iers may be sought • Desktop geotechnical/ ecology/heritage /planning study undertaken, and some fieldwork may be undertaken in identified high risk areas • Major landowners identified • Credible network option further refined • Biodiversity offset liability estimated based on ecology reports available • Corporate cost budget estimated at a high level	• Detailed technical specifications completed for market costing • Market engagement complete, procurement substantially progressed • Detailed geotechnical investigations substantially progressed • Procurement of options over easement commenced, initial consultation with landowners substantially complete • Alignment finalised apart from micrositing issues • Biodiversity offset liability determined and strategy finalised • Ecology/heritage studies substantially progressed • Planning approval commenced • Corporate cost budget finalised
Indicative Class	Class 5b or 5a	Class 5a or 4	Class 4 or 3	Class 4 or 3	Class 3 or better ‡

Stage	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)†
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

† Regulations differ in Victoria, where there is no CPA stage following the RIT-T.
‡ 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 produced 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. In order to include stakeholder and TNSP feedback from the consultation in the short timeframe available, Class 5b estimates were produced by applying a factor to the output from the database to reflect the reduced certainty in concept level estimates. This methodology is detailed in Section 2.2.2 below. Future versions of the database will be updated to include Class 5b outputs.

As the projects move into preparatory activities or become actionable, the TNSPs produce Class 5a, 4, 3 or 2 estimates as they become further defined.

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

AEMO includes all committed and anticipated projects in all future states of the world, in accordance with the AER's CBA Guidelines[12]. 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.

2.2 Transmission Cost Database

The Transmission Cost Database was produced in response to stakeholder feedback on the 2020 ISP. Its objective is to provide increased transparency and accuracy of estimates of costs of future ISP projects, thereby enhancing the ISP outcomes and increasing stakeholder confidence in the estimates.

AEMO engaged GHD as an expert independent consultant to create the Transmission Cost Database, and collaborated with National Electricity Market (NEM) TNSPs and the AER during its design and construction. Stakeholder webinars were held in January, April and June 2021. Recordings and other material can be found on AEMO's website[13].

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 Figure 1, 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

[12] AER. *Cost Benefit Analysis Guidelines*, available at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[13] AEMO. *Opportunities for engagement*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

Database has been published to allow stakeholders to access the detail within the cost estimates, when assessing and providing feedback during the consultation.

2.2.1 Cost estimate components and treatment of risk

For the purposes of the Transmission Cost Database, cost estimates are broken down into several components:

- Building blocks and baseline cost.
- Adjustments for project specific attributes.
- Known risk allowance.
- Unknown risk allowance.
- Indirect costs.

These components are described in the following sections.

Building blocks

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 2.7 and Section 4 of this report. In addition, the numerical and percentage value of each adjustment factor is presented in the detailed output file for each project[14].

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.

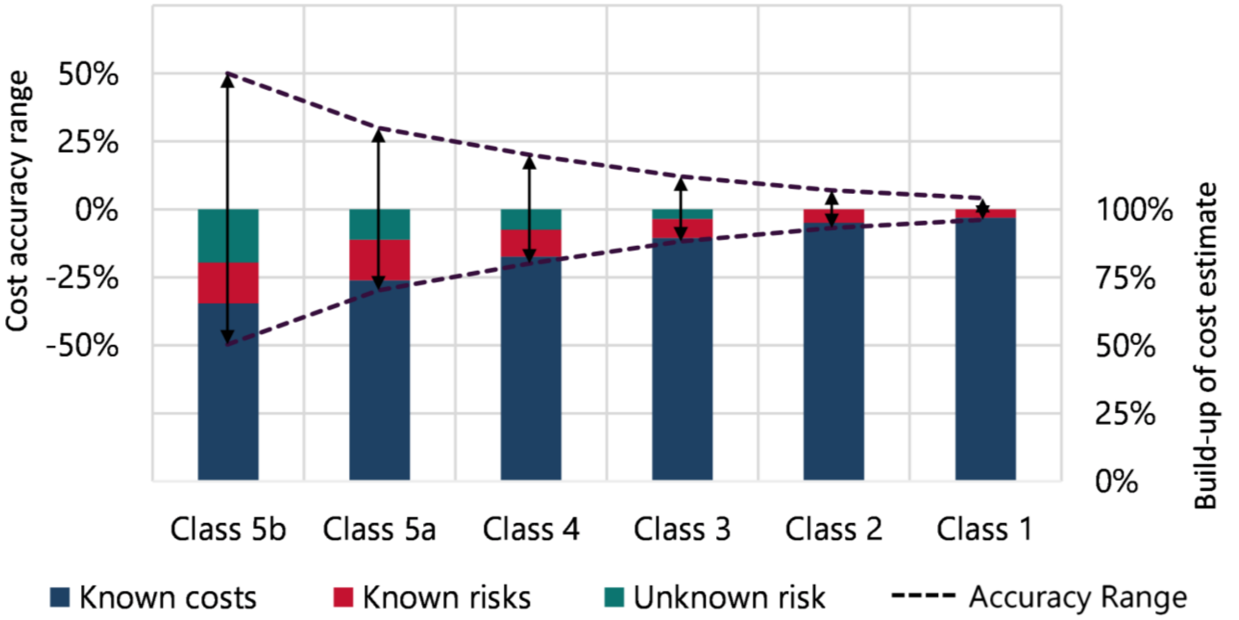
[14] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

2.2.2 Cost estimate progression

Figure 3 illustrates conceptually the summary cost structure used by the Transmission Cost Database. The relative heights of the bars in this figure are indicative and will vary according to the 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 to delivery.

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. It may be helpful to note that the final investment decision is not made by the AER until the CPA stage, and therefore the estimates produced for ISP modelling at earlier stages will have broader accuracy bands than that required for the CPA.

Figure 3 Cost estimate summary breakdown from Class 5b to Class 1



Class 5a/5b Definition

As discussed in Section 2.1, in response to stakeholder feedback on the draft report, AEMO introduced additional stages within Class 5 to better reflect the range of estimates and accuracies that are available within the Australian regulated electricity sector. These are defined in Table 7, with further explanation below.

Table 7 Class 5 estimate sub-categories

Class	Definition	Unknown risk allowance[2]	Accuracy[1]
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%

Notes:
1. 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.
2. Unknown risk allowance defined as a percentage of the known cost (adjusted baseline cost).

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 produced Class 5a estimates. The accuracy of the Class 5a estimates produced by the Transmission Cost Database is ±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[15]. 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.

It is intended that future versions of the database will include functionality to produce Class 5b estimates as well, however the schedule did not allow for updating of the database prior to publication of this report. Instead, GHD extended the statistical analysis to produce the unknown risk and accuracy listed above for Class 5b estimates, where there is increased likelihood of under-runs and over-runs due to the lower concept level scope definition.

AEMO allocated the original Class 5 estimates to either 5a or 5b, based on the degree of scope definition and TNSP involvement that was applied to each future ISP project. A factor was then applied to database outputs for any projects which are considered Class 5b to reflect the higher unknown risk allowance. For Class 5b projects, the cost estimate is produced as follows:

- Class 5b estimate = Class 5a estimate from database x (130%) / (115%)

The database output files for Class 5b projects were updated to reflect this methodology.

2.2.3 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.

The algorithms within the Transmission Cost Database are written using VBA programming language within macros. 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[16].

Full details of the Transmission Cost Database construction including cost and risk data sources are given in GHD's report[17].

An illustration of the detailed cost breakdown structure used in the cost estimation tool is provided in Figure 4. This shows how each main component of the estimate (such as 'building blocks' or 'known risks', as described in Section 2.2.1) is broken down into sub-components for user input, which are then combined to build up the full estimate.

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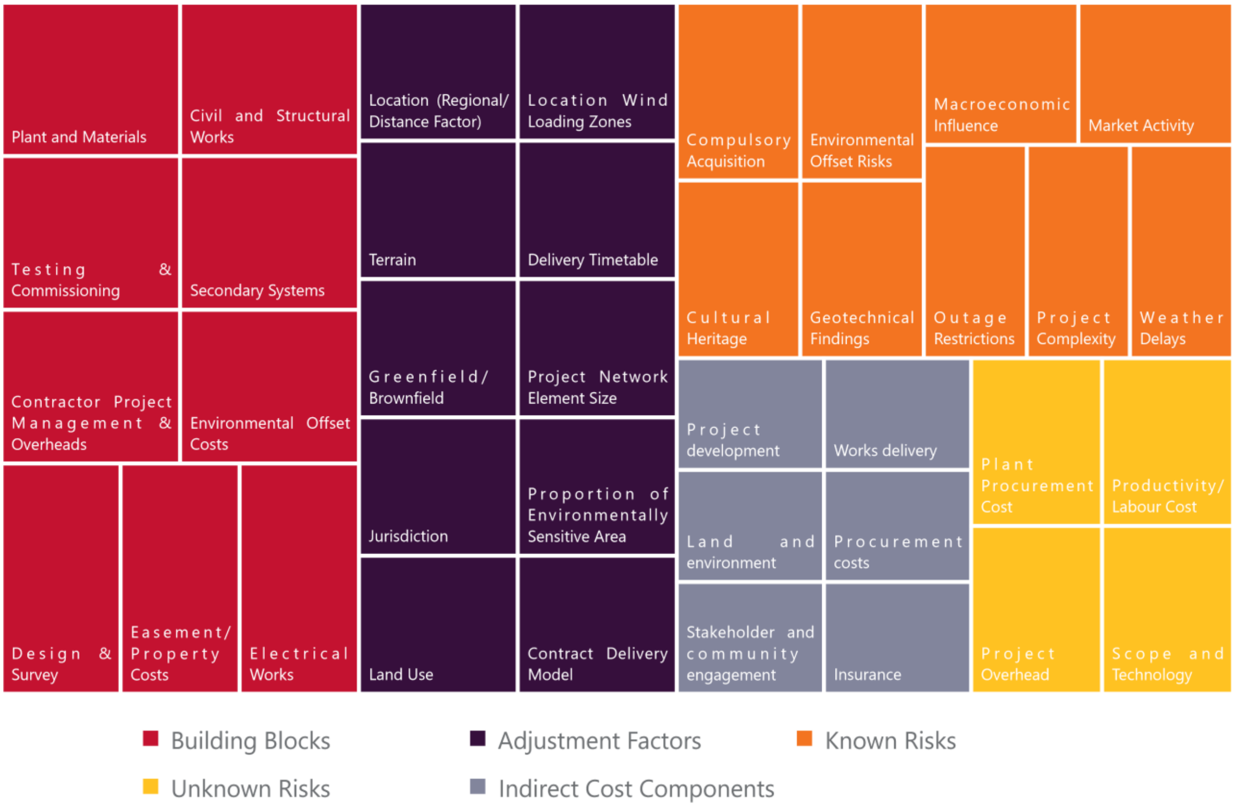
[15] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

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

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

Figure 4 Cost breakdown structure



To select a building block in the estimating tool, the user chooses from lists of plant items, which are broken into categories (for example, overhead line, station), and sub-categories (such as 330 kV overhead line, 500/330 kV transformer). The user then selects the appropriate adjustment factors and risks for each item. A complete listing of the categories and sub-categories that make up the estimates is provided in GHD's report, and detailed notes with guidance for selection of adjustment and risk factors are included within the Transmission Cost Database itself.

Large projects are broken down into several network elements, such as a segment of a major transmission line, or a major substation component, and adjustments and risk factors are applied to the building block costs for each network element. These costs are then summed, along with indirect costs for the overall project, to produce the expected project cost.

The calculation sequence used in the Transmission Cost Database is described below.

Table 8 Transmission Cost Database calculation sequence

Reference	Cost estimate component
n	Number of network elements in a project [Project = network element$_1$ + network element$_2$ + ... + network element$_n$]
A	Baseline cost estimate for a given network element
B	Adjusted baseline cost estimate for a given network element
C	Allowance for known risks associated with a given network element
D	Allowances for unknown risks associated with a given network element
E	(B + C + D) for a given network element

Reference	Cost estimate component
$\sum E_{1\ to\ n}$	$E_1 + E_2 + \ldots\ldots + E_n$
F	Indirect costs for the overall project
G	$\sum E_{1\ to\ n} + F$ = Expected project cost

2.2.4 Calibration

Due to the lack of recent large-scale transmission line projects constructed in Australia, a selection of network elements from large-scale transmission and substation projects were used to calibrate the cost and risk data in the Transmission Cost Database. Many of these projects were in advanced stages of project design. Limited data was available for benchmarking of property and biodiversity costs, so these parameters were estimated by GHD based using inhouse data.

Following this calibration, the majority (14 of the total 16 network elements) of the Transmission Cost Database outputs were within ±15% of the benchmark reference cost estimates. This positioning provides confidence that the cost estimates generated by the Transmission Cost Database are in alignment with the latest industry reference.

2.2.5 Limitations

Property and environmental offset costs

The project property/easement and environmental offset cost components are a function of the site or land footprint area needed, the locational characteristics of the land and the project risk profile.

Following publication of the *Draft 2021 Transmission Cost Report*, errors were discovered in the property and environmental offset costs used in the Transmission Cost Database. Given the comparatively small amount of land/easement needed for substations, these two components are relatively more significant in the overhead line network element costs compared to the substation network element costs.

A review of the impact of the errors has determined that the average impact on the expected project cost estimates is in the range of -4% to +4%, however for the unlikely combination of only overhead line elements and a specific set of project characteristics, the error may be as high as ±15%.

Across the portfolio of future ISP projects with diverse characteristics, the error in the expected project costs is small, however the errors on the individual property and biodiversity component costs are larger. Therefore, users are advised not to rely on these specific property and environmental offset component costs listed in the output files associated with this report.

The errors have been corrected in the latest version of the database, published alongside this report. However, the publication schedule did not allow for updates to be made to the cost estimates published within this report. Depending on the materiality of this error, AEMO may update transmission costs throughout the course of ISP modelling.

Conceptual scope estimates

As discussed in Section 2.2.2, the current database produces Class 5a estimates, and a manual adjustment is required to produce Class 5b estimates.

Other

The user needs to input and choose their selections in the *Transmission Cost Database* based on the assumed scope and definition of the project. Detailed knowledge of and experience in power system design is an essential requirement to be able to accurately specify the inputs to the tool so as to get reasonable outcomes.

Users should also note the following:

- The output is a Class 5a estimate (which can be adjusted for Class 5b) and therefore suitable only for estimating the costs of network options which are in the very early stages of development for use in the ISP modelling. The database is not suitable for Class 4 or better estimates – these should be produced by TNSPs using a more detailed approach.
- The output is a point estimate calculated in a deterministic or parametric fashion. In other words, it is not a 'P-' estimate and does not have any associated statistical qualification (for example, confidence level, probability distribution functions, standard deviation). No stochastic simulation was involved in the Transmission Cost Database cost estimation.
- 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 building block costs are in real 2021 Australian dollar values, therefore, the output is in real 2021 Australian dollars. AEMO may adjust the output using CPI to ensure consistency with other costs in the ISP.
- The output represents Australian construction environment, asset and design standards, industry and business practices, regulatory framework, commercial rules, labour laws, and safety regulations in 2021.
- The output represents stable macroeconomic (forex, commodity, labour and wage price indices), social and political conditions that Australia has experienced in recent years up to 2021.
- The output represents efficient preliminary investigation, project development, project management, competitive tendering, site management and contractual arrangements.

2.3 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.

While AEMO has adopted the AACE standard for the ISP, this standard is not currently a requirement for TNSPs. 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.

2.3.1 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.

2.3.2 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.

2.3.3 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 2.2.2).
   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.

2.3.4 Review outcomes

AEMO received completed TNSP checklist responses and TNSP cost estimates for actionable projects and projects with preparatory activities from most TNSPs during June 2021.

TransGrid projects

Estimates for costs for HumeLink and the New South Wales works on VNI West are included using TransGrid's estimates. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

The project scopes and cost estimates requested for TransGrid's preparatory activities were provided to AEMO, but the cost estimates were provided on a confidential basis. Because the ISP regulatory framework is designed to be transparent and consultative for all stakeholders, AEMO does not consider it appropriate to use confidential transmission costs in the ISP. These preparatory activities projects were therefore costed by AEMO on a Class 5b basis using the Transmission Cost Database and using TransGrid's provided scope as a starting point.

Other TNSPs' projects

All other projects were reviewed according to the process described above, and the results are shown in Table 9. No significant omissions or discrepancies were found, and therefore no adjustments were required.

Following clarifications on the basis, the class, accuracy and cost estimate supplied by the TNSPs, their estimates were adopted for each project, as listed in the relevant sections of this report.

Table 9 Review of TNSP cost estimates - results

Project	Expected Cost ($B)			Estimated class		Accuracy Band		Total Risk Allowance	
	AEMO	TNSP[A]	Difference	AEMO[E]	TNSP	AEMO[A]	TNSP	AEMO	TNSP
Preparatory activities									
QNI Medium Stage 1 (QLD works only)	0.49	0.59	21%	5	5	±75%	±75%	26%	30%
QNI Large Stage 2 (QLD works only)	0.16	0.20	24%	5	5	±75%	±75%	15%	30%
Gladstone Grid Reinforcement	0.42	0.41	-2%	5	5	±75%	±75%	23%	30%
Facilitating power to southern Queensland - Option 1	0.57	0.48	-16%	5	5	±75%	±75%	26%	30%
Actionable projects									
Marinus Link[B] (HVAC Stage 1)	0.46	0.57	22%	4	4	±15%	±15%	16%	13%
Marinus Link[B,F] (HVAC Stage 2)	0.10	0.10	-7%	4	4	±15%	±15%	17%	13%
VNI West[C] (via Kerang) (VIC works only)	1.35	1.29	-4%	4	3/4	±30%	±30%	16%	N/A[D]
VNI West[C] (via Shepparton) (VIC works only)	1.31	1.25	-4%	4	3/4	±30%	±30%	18%	N/A[D]

A. Where the TNSP estimate is used for input to the ISP, AEMO has adopted the accuracy quoted by TNSP.
B. AEMO did not have sufficient independent cost data to estimate the HVDC portion of Marinus Link, hence only the HVAC portion was used for the comparison exercise. The full cost is shown in Section 3.10.
C. VNI West Victorian works data and checklist were provided by AEMO Victorian Planning. TransGrid did not provide risk allocation data and provided a cost estimate checklist on a confidential basis only, so it is therefore not possible to assign a class or accuracy to this project overall without breaching confidentiality.
D. The VNI West TNSP estimate methodology incorporated unknown risk into the adjustment factors, so was not stated as a separate line item.
E. This column reflects the outcome of AEMO's review of the TNSP estimate class using the common checklist, developed in collaboration with all TNSPs.
F. Costs are rounded to two significant figures.

2.4 Estimating operational expenditure

To estimate the operational expenditure for transmission projects, 1% of the total capital cost per annum is assumed as operation and maintenance cost for each transmission project.

If more detailed information is provided from a TNSP, and AEMO is satisfied with the evidence provided, this may take precedence over the 1% assumption.

2.5 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 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 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 rules, 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[18] 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 is not feasible, underground options will be considered.

Where an impact, or disbenefit, 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

[18] 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.

impacts[19]. Similarly, the regulations do not allow consideration of wider benefits of building or maintaining transmission infrastructure such as increased regional jobs, local manufacturing, utilisation of local contractors, training and apprenticeships, or economic opportunities unlocked or facilitated by the projects.

Importantly, while the regulatory process that underpins the ISP and any future RIT-T is undertaken on a cost-benefit analysis, these are only some of the preliminary steps that occur before each project obtains the necessary planning and environmental approvals. Broader social and environmental impacts are thoroughly considered as part of the 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) (see Section 2.6).
- 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 feasible:

- HVAC underground cable is suited to lengths below approximately 50 km. Beyond 50 km length, AC lines at high voltage level will be subject to very large charging currents, requiring significant reactive compensation and design considerations.
- For HVDC options, a long length of underground cable is feasible.
- 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.

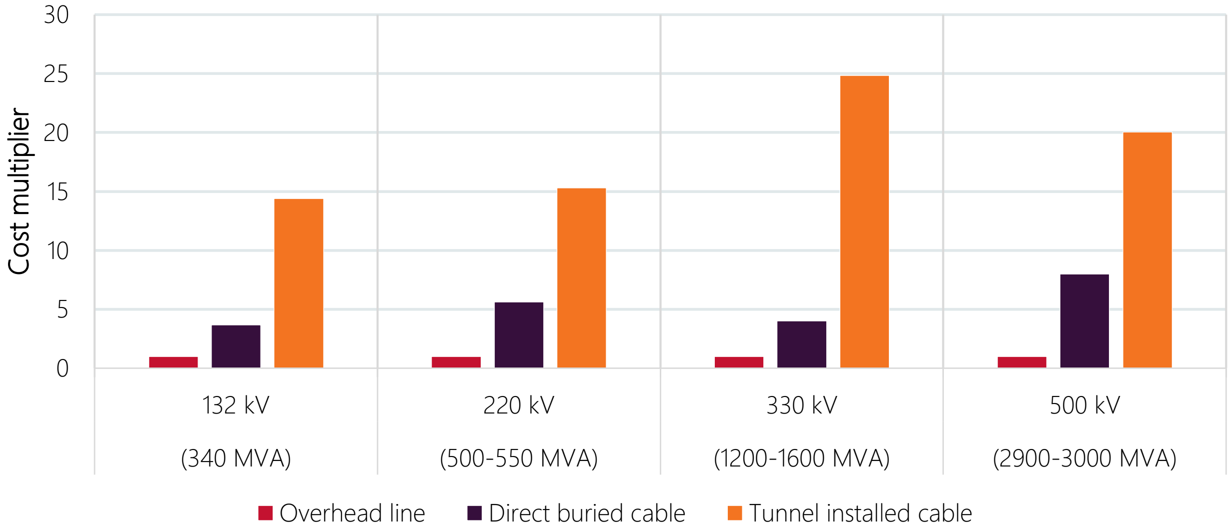
The Transmission Cost Database includes cost estimates for overhead transmission lines and underground cables, both of which vary significantly with voltage level and capacity.

Figure 5 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

[19] 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.

25 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 5 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 330 kV HVAC options, but the cost factor increase is higher when undergrounding a 330 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.

2.6 Selection of technologies

This section discusses technology options and their cost sources, including:

- Technology to provide virtual network, such as batteries with fast acting control systems to increase transmission link capacity without building new line assets.
- Technology to maximise utilisation of existing assets, such as control schemes, modular power flow controllers, phase shifting transformers.
- HVAC versus HVDC.
- Voltage selection.

Energy storage and virtual transmission lines

Energy storage at certain points in the power system can support the existing network infrastructure and enhance the performance of the power system. Energy storage close to the sending end of the network can store renewable generation at times of grid congestion and release it at times of less congestion. Energy storage at the receiving end can store the energy at times of excess supply and discharge at times of supply shortfall.

Also, with energy storage, power transfer capability across the existing network can be increased. This combination of storage and transmission lines is referred to as a "virtual transmission line" (VTL). VTL is an application of energy storage systems to manage network congestion without interfering in the balance between demand and supply. Transmission capability along a path can be increased up to thermal capacity for system normal operation. Following a contingency, the overload can be removed immediately by reducing supply at the sending end (charging by energy storage system) and increasing supply in the receiving end (discharging by energy storage system or reducing demand). This requires fast acting control schemes.

Technology and cost of energy storage and associated fast acting control schemes is market-driven.

Control schemes

In the NEM, a number of fast acting control schemes, referred as special protection schemes (SPS) or system integrity protection schemes (SIPS), are in place to manage the power system security immediately after a credible contingent event. These schemes allow increased power transfer in normal operation, and reduce or disconnect generation or reduce demand following a contingency event to maintain power system security. Fast acting control schemes are considered as an alternative to upgrading or building new transmission options.

Design and cost estimation of SPS or SIPS are specific to contingency and system security management for each project. The Transmission Cost Database provides generic cost estimates of SPS.

Power flow controllers

In a meshed AC transmission network, power flow can be unevenly shared between the parallel transmission lines. The amount of power on an individual line is a function of its fixed impedance. Transfer capability can thus be limited because one line on the flow path is at its limit while another is under-utilised. A power flow controller is an alternative technology which can be applied to increase transfer capability by shifting power from an over-utilised line to under-utilised lines. As an alternative to transmission infrastructure upgrade, phase shifting transformers and modular power flow controllers are being considered in the development of transmission options for the ISP.

The Transmission Cost Database provides cost estimates of phase shifting transformers and modular power flow controllers.

HVAC versus HVDC

Alternative transmission options identified in the ISP include HVAC and HVDC transmission systems. HVDC transmission systems require an AC to DC converter station at the sending end and a DC to AC converter station at the receiving end. The HVAC transmission line has an advantage of enabling connection of more renewable generation along the transmission path with relatively very low cost of connection points compared to expensive additional converter stations in the HVDC transmission system.

The Transmission Cost Database provides cost estimates per km for HVAC and HVDC transmission lines and converter stations at different voltage levels up to 500 kV.

Voltage selection

Most of the existing extra high voltage transmission network in the NEM is HVAC and is designed to operate at nominal voltages of 220 kV, 275 kV, 330 kV, or 500 kV. The following factors are considered in the selection of new transmission augmentation options:

- Operating voltage level of existing transmission network and options to integrate the new transmission lines within the existing electricity network.
- Transfer capacity – higher voltages accommodate higher transfer capacity.
- Consideration of reduced numbers of transmission lines to access remote generation to load centres.
- Network losses – higher voltages result in lower network losses.
- The capacity of the network augmentation is designed and refined through power system analysis.

The Transmission Cost Database provides cost estimates per km for HVAC and HVDC transmission lines and components of HVAC substations and converter stations at different voltage levels up to 500 kV.

2.7 Market impacts on transmission costs

There is the potential that delivery of multiple coincident projects will impact transmission costs, both in labour and materials. Infrastructure Australia has partnered with AEMO to assess and understand the employment and material requirements for the transmission and generation projects identified in AEMO's 2020 ISP. This new analysis, scoped collaboratively with AEMO and commissioned by Infrastructure Australia from the University of Technology Sydney, aims to improve the understanding of labour and material requirements to inform and assist governments, TNSPs, project developers, and market bodies.

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 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 any accuracy. It is expected that the Class 3 and 4 projects estimated by the TNSPs will have allowances included for market pressure, since these are to be constructed in a shorter time horizon.

3. Flow paths

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

Some upgrades to flow paths are already committed or anticipated (see Table 2). This chapter presents credible 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.
- An overview of characteristics which are key cost drivers.

Many of augmentation options included in this section are either undergoing a RIT-T (see Table 3) or have preparatory activities being developed (see Table 4). Where available, transfer limits and cost estimates of these augmentation options were sourced from respective TNSPs and included in the final 2021 Transmission Cost Report.

3.1 Overview

The augmentation options to increase the transfer capability of flow paths presented in this section are aligned with the network topology presented for 2022 ISP in the 2021 IASR[20]. Augmentation options between the sub-regions are also presented in the 2021 IASR.

These augmentation options can be categorised as follows:

- **Central and North Queensland (CNQ) to Gladstone Grid (GG)** – also referred to as "Gladstone Grid Reinforcement", this is an option to increase transfer capacity between the CNQ and GG sub-regions for which AEMO triggered preparatory activities – see Section 3.3.
- **Southern Queensland (SQ) – CNQ** – options to increase transfer capacity between the SQ and CNQ sub-regions, including the Central to Southern Queensland Transmission Link for which AEMO triggered preparatory activities – see Section 3.4.
- **Northern New South Wales (NNSW) – SQ** – options to increase the transfer capability between NNSW and SQ. This includes components of the QNI Medium and Large projects for which AEMO triggered preparatory activities – see Section 3.5.
- **Central New South Wales (CNSW) – NNSW** – options to increase the transfer capability between CNSW and NNSW. This includes components of the QNI Medium and Large projects and components of New

[20] AEMO, *2021 Inputs and Assumptions Workbook*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

England and North West New South Wales REZ upgrades for which AEMO triggered preparatory activities – see Section 3.6.

- **CNSW – Sydney, Newcastle and Wollongong (SNW)** – options to reinforce supply to Sydney, Newcastle and Wollongong load centres following retirement of coal power generators in New South Wales. This includes the Reinforcing Sydney, Newcastle and Wollongong Supply project for which AEMO triggered preparatory activities – see Section 3.7.
- **Southern New South Wales (SNSW) – CNSW** – options to increase the transfer capability between SNSW and CNSW, currently proposed to be increased via the HumeLink[21] project – see Section 3.8.
- **Victoria – SNSW** – options to increase the transfer capability between Victoria and SNSW. This includes augmentation options considered as part of the VNI West[22] project – see Section 3.9.
- **Tasmania – Victoria** – this includes Project Marinus Link[23], a proposed new interconnector to increase the transfer capability between Tasmania and Victoria – see Section 3.10.

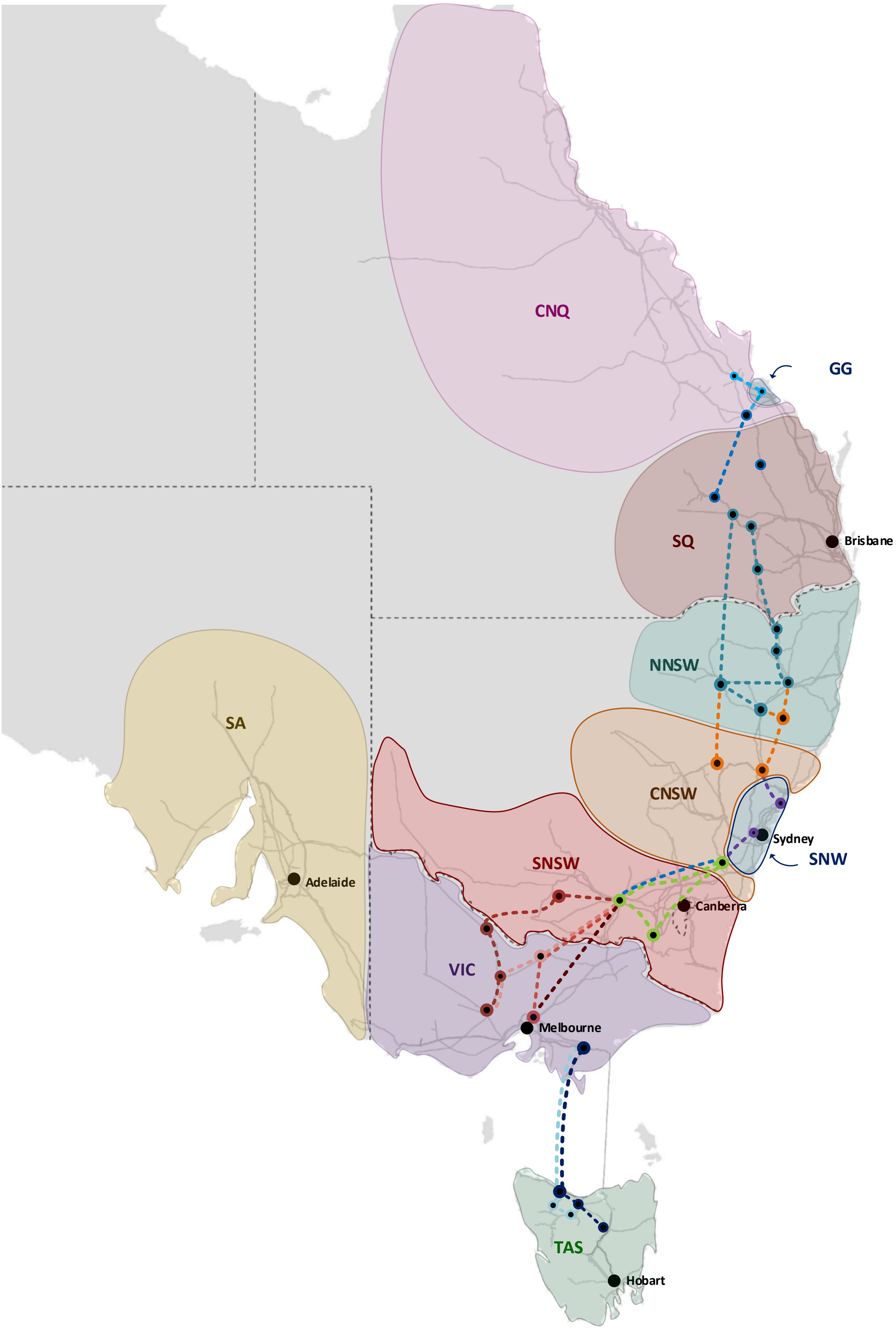
The different corridors associated with these options are illustrated in Figure 6 and described in more detail in the following sections.

[21] TransGrid. *HumeLink*, at https://www.transgrid.com.au/humelink.

[22] AEMO. *VNI West*, at https://aemo.com.au/en/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.

[23] TasNetworks. *Marinus Link*, at https://www.marinuslink.com.au/.

Figure 6 Flow path development options



3.2 Legend and explanation of tables

The tables in sections 3 and 4 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 2020 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 or power flow studies.

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, as referred to 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><td colspan="2">Augmentation options – these include the capability, cost and timing for flow path augmentation options</td></tr>
<tr><td>Additional network capacity (megawatts [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 2021 figures in ($ million). All cost estimates, except for projects currently progressing in RIT-T and identified as preparatory projects in the 2020 ISP, are indicative and sourced from AEMO's Transmission Cost Database. Where available, cost estimates for projects which are currently progressing in RIT-T or preparatory activities were sourced from respective TNSPs. 'Expected cost' denotes statistically most likely estimate, based on the analysis of historical data used to benchmark the database.

Costs shown in this report are rounded to nearest whole number.</td></tr>
<tr><td>Cost classification</td><td>This is based on either AEMO's Transmission Cost Database or TNSPs' cost estimates information based on the AACE Cost Estimate Classification System as referenced in Section 2.3.</td></tr>
<tr><td>Lead time</td><td>Represent the likely minimum time for service from the date of publication of the final 2022 ISP. The lead time includes regulatory justification and approval, relevant community engagement and planning approvals, procurement, construction, commissioning, and inter-network testing. This lead time is categorised as short (1-3 years), medium (3-5 years), or long (beyond five years).</td></tr>
<tr><td 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.</td></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).
• Legislation jurisdiction (New South Wales, Queensland, South Australia, Tasmania, and Victoria).
• Scale modifiers (transmission line length, project size).
• Delivery timeframe (optimum, tight, long).
• Contract delivery model (engineering, procurement, and construction [EPC] contract, design and coinstruct [D&C] contract) – EPC contract is chosen unless otherwise specified.
• Proportion of environmentally sensitive areas (None, 25%, 50%, 75% and 100%).
• Location wind loading zones (cyclone and non-cyclone regions) – non-cyclone region is chosen unless otherwise specified.</td></tr>
</table>

Known risk: where the risks are identified but ultimate value is not known. There are nine known risk factors: • Compulsory acquisition (business as usual [BAU], low and high). • Cultural heritage (BAU, low and high). • Environmental offset risks (BAU, low and high). • Geotechnical findings (BAU, low and high). • Macroeconomic influence (BAU, increased uncertainty and heightened uncertainty). • Market activity (BAU, tight and excess capacity). • Outage restrictions (BAU, low and high). • Project complexity (BAU, partly complex and highly complex). • Weather delays (BAU, low and high).
Unknown risk: where the risk has not been identified but industry experience indicates these could occur: • Scope and technology. • Productivity and labour cost. • Plant procurement cost. • Project overhead.

3.3 Central and North Queensland to Gladstone Grid

Summary

With retirement or reduced generation from Gladstone Power Station and increased generation in North Queensland, the demand at Boyne Island, Calliope River, Larcom Creek and Raglan substations cannot be supplied.

In the 2020 ISP, AEMO recommended Powerlink complete preparatory activities for reinforcement of Central and North Queensland (CNQ) and Gladstone Grid (GG) section. One network option is proposed to increase the maximum network transfer capability between CNQ and GG.

Existing network capability

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

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

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 275 kV double-circuit line between Calvale and Calliope River. • Rebuild Calliope River to Larcom Creek 275 kV double-circuit line. • Rebuild Larcom Creek to Bouldercombe 275 kV double-circuit line with one line tapped at Raglan. • A new (third) 275/132 kV transformer at Calliope River. *Provided by Powerlink – see Section 1.1.*	CNQ to GG: 550 MW GG to CNQ: 500 MW	408	Class 5 (±75%)	October 2030 (5 years from project approval)

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Refer to Powerlink's Preparatory Activities Gladstone Grid Reinforcement report[24].	

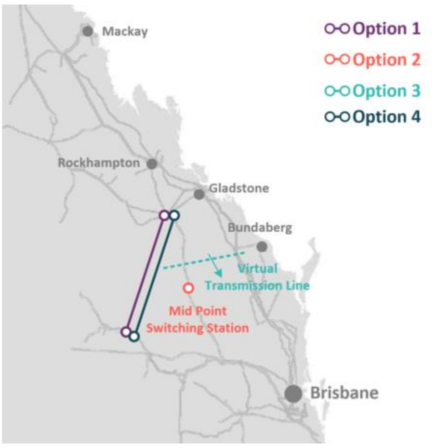
[24] At https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

3.4 Southern Queensland to Central & North 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 the 2020 ISP, AEMO recommended Powerlink complete preparatory activities to increase transfer capability from CNQ to SQ. Four options are proposed to increase the maximum network transfer capability between CNQ and SQ.



Existing network capability

CNQ 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 CNQ to SQ grid section is limited by transient or voltage stability following a Calvale to Halys 275 kV circuit contingency.

In the reverse direction, SQ to CNQ maximum transfer capability is 700 MW at peak demand and summer typical levels and 1,000 at winter reference periods. The maximum transfer capability from SQ to CNQ is limited by thermal capacity of the Blackwall–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[25]: • A new 275 kV double-circuit line between Calvale and South West of Queensland. • 275 kV line shunt reactors at both ends of Calvale - South West of Queensland 275 circuits. *Provided by Powerlink – see Section 1.1.*	North: 900 MW South: 900 MW REZ NQ3: 900 MW	476	Class 5 (±75%)	December 2028 (5 years from project approval)
Option 2: • Mid-point switching substation on the Calvale – Halys 275 kV double-circuit line.	North: 300 MW South: 300 MW REZ NQ3: 300 MW	55	Class 5a (±30%)	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.	North: 300 MW South: 300 MW REZ NQ3: 300 MW	To be provided by interested parties		
Option 4: • A 1,500 MW HVDC bi-pole overhead transmission line from Calvale and 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.	North: 1,500 MW South: 1,500 MW REZ NQ3: 1,500 MW	1,615	Class 5b (±50%)	Long

[25] Option 1 costs were provided by Powerlink. Class and the accuracy band as per Powerlink advice.

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Refer to Powerlink's Preparatory Activities CQSQ Transmission Link report[26].	
Option 2	• Location: Regional • Proportion of environmentally sensitive areas: 50% • Land use: Scrub • Delivery timetable: Optimum • Project size: 1-5 bays	• Known risks: BAU • Unknown risks: Class 5 • Outage restrictions: High
Option 3	• Pending information from interested parties.	
Option 4	• Location: Remote • Land use: Grazing • Project size: applicable for HVDC converter station • Terrain: Flat/Farmland • Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Unknown risks: Class 5 • Project complexity: Highly complex

[26] AEMO. *Inputs, Assumptions and Scenarios Report*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

3.5 Northern New South Wales – 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 upgrades.

A project to increase the transfer capacity of the existing QNI (referred as 'QNI Minor') has been committed.

In addition to QNI Minor, in the 2020 ISP, AEMO recommended Powerlink and TransGrid complete preparatory activities for QNI Medium and Large interconnector upgrades. Alternative options were proposed by Powerlink and TransGrid.

Including alternative options, four options are proposed to increase the maximum network transfer capability between NNSW and SQ.

Existing network capability

Transfer capability with future options will be modelled with QNI minor upgrade in service.

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

Augmentation options

Description	**Additional network capacity (MW)**	**Expected cost ($ million)**	**Cost classification**	**Lead time**
Option 1*****: • A new 330 kV double-circuit line (one circuit strung) from locality of Armidale South 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 Bulli Creek for the Bulli Creek–Braemar and Dumaresq–Bulli Creek 330 kV circuits. *QLD scope and cost provided by Powerlink – see Section 1.1.* *NSW scope provided by TransGrid – see Section 1.1.*	North: 910 MW South: 1,080 MW	1,253(Combined cost of NSW and QLD works)	Powerlink cost Class 5 (±75%) AEMO TCD for NSW works Class 5b (±50%)	Long
Option 2*****: • An additional new 330 kV circuit (second circuit strung) from locality of Armidale South to Dumaresq to Bulli Creek to Braemar. • 330 kV Line shunt reactors at Bulli Creek for the Bulli Creek–Braemar and Dumaresq–Bulli Creek 330 kV circuits. *Pre-requisite: NNSW-SQ Option 1* *QLD scope and cost provided by Powerlink – see Section 1.1.* *NSW scope provided by TransGrid – see Section 1.1.*	North: 550 MW South: 800 MW	384(Combined cost of NSW and QLD works)	Powerlink cost Class 5 (±75%) AEMO TCD for NSW works Class 5b (±50%)	Long

Option 3: • A Virtual Transmission Line option with a 300 MW energy storage system south of Armidale and north of Braemar.	300 MW in both directions.	*To be provided by interested parties*		
Option 4: • A 2,000 MW HVDC bi-pole overhead transmission between a new substation in North West New South Wales (NWNSW) REZ and Western Downs. • 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 Western Downs. • AC network connection between HVDC converter station and 275 kV substation in Western Downs. • AC network connection between HVDC converter station and ac network in in NWNSW REZ. • A new 330 kV line between NWNSW REZ and Tamworth.	North: 1,800 MW South: 2,000 MW	3,125	Class 5b (±50%)	Long

Adjustment factors and risk				
Option	**Adjustment factors applied**		**Known and unknown risks applied**	
Options 1 and 2 (QLD works)	• Refer to Powerlink's Preparatory Activities QNI Medium and Large report[27].			
Option 1 and 2 (NSW works)	• Location: Remote • Land use: Grazing • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Environmental offset: High • Unknown risks: Class 5	• Market activity: Tight • Compulsory acquisition: High
Option 3	• Pending information from interested parties.			
Option 4	• Location: Remote • Land use: Grazing • Project size: applicable for HVDC converter station • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Unknown risks: Class 5	• Project complexity: Highly complex

*AEMO requested that TransGrid provide information on these options through preparatory activities as per clause 5.22.6(c) in NER. Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

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

3.6 Central New South Wales to Northern New South Wales

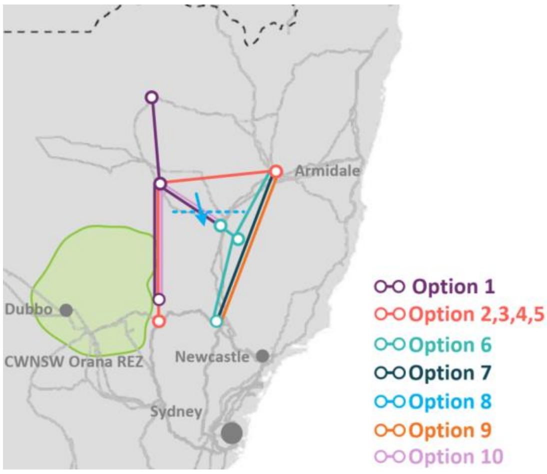
Summary

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 the southern sections of proposed QNI upgrades.

A project to increase the transfer capacity of the existing QNI (referred as 'QNI Minor') has been committed.

In addition to QNI Minor, in the *2020 ISP*, AEMO recommended that Powerlink and TransGrid complete preparatory activities for QNI Medium and Large interconnector upgrades and TransGrid complete preparatory activities for New England REZ and North West REZ. Alternative options were proposed by TransGrid.

Including alternative options, 10 options are proposed to increase the maximum network transfer capability between CNSW and NNSW.



Note: The Central West Orana REZ is shown in green – see Section 4.2.3 for more information.

Existing network capability

Transfer capability of future options will be modelled with QNI minor upgrade in service.

- 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 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*: • 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.	North: 2,035 MW South: 1,660 MW REZ N1: 1,660 MW	3,578	Class 5b (±50%)	Long
Option 2*: • A new 500 kV single-circuit line from locality of Armidale South to locality of Boggabri to Orana REZ. • A new single 500 kV circuit from Orana REZ to Wollar. • A new 500/330 kV substation with two 1,500 megavolt-amperes (MVA) transformers in locality of Armidale South.	North: 710 MW South: 535 MW REZ N1 & N2: 535 MW	1,928	Class 5b (±50%)	Long

• A new 500 kV switching station in locality of Boggabri. • A new 500 kV switching station in locality of Boggabri. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth–Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 500 kV line shunt reactors at both ends of locality of Armidale South–locality of Boggabri, locality of Boggabri–Orana REZ and Orana REZ–Wollar.				
Option 3*: • An additional new 500 kV single-circuit line from locality of Armidale South to locality of Boggabri to Orana REZ. • 500 kV line shunt reactors for the additional 500 kV line at both ends of locality of Armidale South–locality of Boggabri and locality of Boggabri–Orana REZ. *Pre-requisite: CNSW-NNSW Option 2*	North: 585 MW South: 470 MW REZ N1 & N2: 470 MW	1,403	Class 5b (±50%)	Long
Option 4*: • A new 500 kV double-circuit (strung on one side) from locality of Armidale South to locality of Boggabri to Orana REZ. • A new single 500 kV circuit from Orana REZ to Wollar. • A new 500/330 kV substation with two 1,500 MVA transformers in locality of Armidale South • A new 500 kV switching station in locality of Boggabri • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth–Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 500 kV line shunt reactors at both ends of locality of Armidale South–locality of Boggabri, locality of Boggabri–Orana REZ and Orana REZ–Wollar 500 kV lines.	North: 710 MW South: 535 MW REZ N1 & N2: 535 MW	1,896	Class 5b (±50%)	Long
Option 5*: • An additional new 500 kV circuit (second circuit strung) from locality of Armidale South to locality of Boggabri to Orana REZ. • 500 kV line shunt reactors for the additional 500 kV circuit at both ends of locality of Armidale South– locality of Boggabri and locality of Boggabri–Orana REZ. *Pre-requisite: CNSW-NNSW Option 4*	North: 585 MW South: 470 MW REZ N1 & N2: 470 MW	510	Class 5b (±50%)	Long
Option 6*: • A new 500 kV double-circuit line from locality of Armidale South to Bayswater via east of Tamworth, • A new 500/330 kV substation with two 1,500 MVA transformers in locality of Armidale South. • A new 500/330 kV substation in locality of east of Tamworth. • A new 330 kV circuit from the locality of east of Tamworth to Tamworth. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale.	North: 2,190 MW South: 1,800 MW REZ N2: 1,800 MW	1,678	Class 5b (±50%)	Long

• Reconnect both Tamworth–Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 500 kV line shunt reactors at both ends of locality of Armidale South–locality of east of Tamworth and locality of east of Tamworth–Bayswater.				
Option 7: • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Liddell. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth–Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South.	North: 1,470 MW South: 1,590 MW REZ N2: 1,590 MW	891	Class 5b (±50%)	Long
Option 8: • Non-network option - A Virtual Transmission Line option with a 300 MW energy storage system south of Liddell and north of Armidale.	North: 300 MW South: 300 MW REZ N2: 300 MW	To be provided by interested parties		
Option 9: • 2,000 MW bi-pole HVDC transmission system between locality of Bayswater and locality of Armidale South. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South.	North: 1,750 MW South: 2,000 MW REZ N2: 2000 MW	2,112	Class 5b (±50%)	Long
Option 10: • 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.	North: 1,750 MW South: 2,000 MW REZ N1: 2000 MW	2,300	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied		Known and unknown risks applied	
Options 1 to 7	• Location: Remote • Land use: Grazing • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Environmental offset: High	• Unknown risks: Class 5 • Market activity: Tight • Compulsory acquisition: High
Option 8	• Pending information from interested parties			
Options 9 and 10	• Location: Remote • Land use: Grazing • Project size: applicable for HVDC converter station • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Environmental offset: High • Market activity: Tight	• Unknown risks: Class 5 • Compulsory acquisition: High • Project complexity: Highly complex for HVDC converter station

*AEMO requested that TransGrid provide information on these options through preparatory activities as per NER clause 5.22.6(c). Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

3.7 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.

In the 2020 ISP, AEMO recommended TransGrid complete preparatory activities for reinforcement of SNW supply. Three options are proposed to increase the maximum network transfer capability from Central New South Wales (CNSW) to SNW.

Existing network capability

Existing transfer capability varies depending on load and generation distribution within Sydney, Newcastle and Wollongong areas.

The maximum transfer capability from CNSW to SNW is 7,525 MW at peak demand and summer typical and 7,625 at winter reference periods. With no Eraring and Vales Point generation, the maximum transfer capability reduces to 6,125 MW at peak demand and summer typical and 6,225 MW at winter reference periods. The maximum transfer capability is limited by a number of 330 kV lines between Bannaby and Liddell following a credible contingency.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1*: SNW Northern 500 kV loop: • A new 500 kV double-circuit line between Eraring substation and Bayswater substation. • A new 500 kV substation near Eraring *(Additional scope added by AEMO)*. • Two 500/330 kV 1,500 MVA transformers at Eraring substation. *Initial scope provided by TransGrid and revised by AEMO – see Section 1.1.*	5,000 (This capacity increase for accommodation of additional new generation from North of Bayswater and 2/3 generation from Central West NSW)	880	Class 5b (±50%)	Long
Option 2*: SNW Southern 500 kV loop: • A new 500 kV double-circuit line from the Bannaby substation to a new overhead/underground transition site. • 8 km of tunnel installed underground 500 kV cables from the transition site to new substation in the locality of South Creek *(Additional scope added by AEMO)*. • Establish 500/330 kV substation in the locality of South Creek. • Cut-in both Eraring – Kemps Creek 500 kV circuits at the new substation in the locality of South Creek. • Two new 500/330 kV 1,500 MVA transformers at the new substation in the locality of South Creek.	4,500 (This capacity increase for accommodation of additional new generation from South of Bannaby and 1/3 generation from Central West to NSW	2,256	Class 5b (±50%)	Long

• Replace a section of existing Bannaby-Sydney West 330 kV to double-circuit line between the locality of South Creek and Sydney West. • Uprate the existing line between Bannaby and the locality of South Creek from 85°C to 100°C operating temperature. • Cut-in Bayswater – Sydney West 330 kV line at South Creek. • Cut-in Regentville – Sydney West 330 kV line at South Creek. *Initial scope provided by TransGrid and revised by AEMO – see Section 1.1.*				
Option 3*: Both SNW Northern 500 kV loop and SNW Southern 500 kV loop • CNSW-SNW Option 1. • CNSW-SNW Option 2.	5,600 (No restriction to generation dispatch from north, south and west of SNW)	3,136	Class 5b (±50%)	Long

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Options 1, 2 and 3	• Location: Regional • Land use: Developed area • Project size: 6-10 bays • Terrain: Hilly/undulating • Partly brownfield • Delivery timetable: Long • Total circuit length: 10-100 km • Proportion of environmentally sensitive areas: 100%	• Known risks: BAU • Environmental offset: High • Compulsory acquisition: High • Unknown risks: Class 5 • Market activity: Tight • Project complexity: Partly complex

*AEMO requested that TransGrid provide information on these options through preparatory activities as per NER clause 5.22.6(c). Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

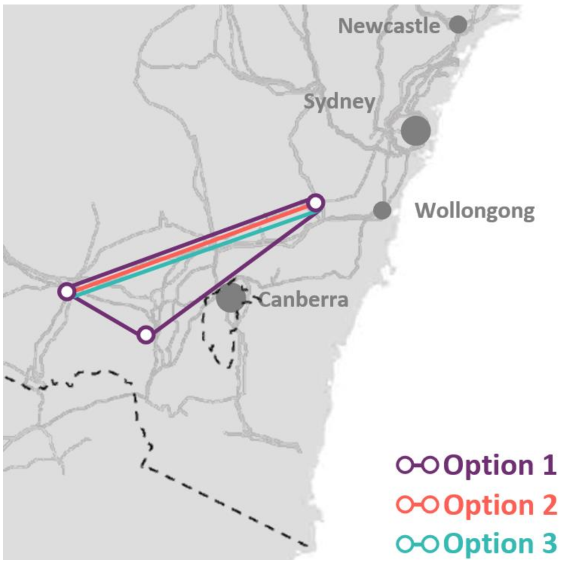
3.8 Southern New South Wales to Central New South Wales

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 is an actionable 2020 ISP project. TransGrid is currently undertaking a RIT-T for this network augmentation. The Project Assessment Draft Report (PADR), the second report of the RIT-T, was published in January 2020.

Subsequent to HumeLink, two 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 or Gullen Range–Bannaby 330 kV lines following a credible contingency.

Augmentation options

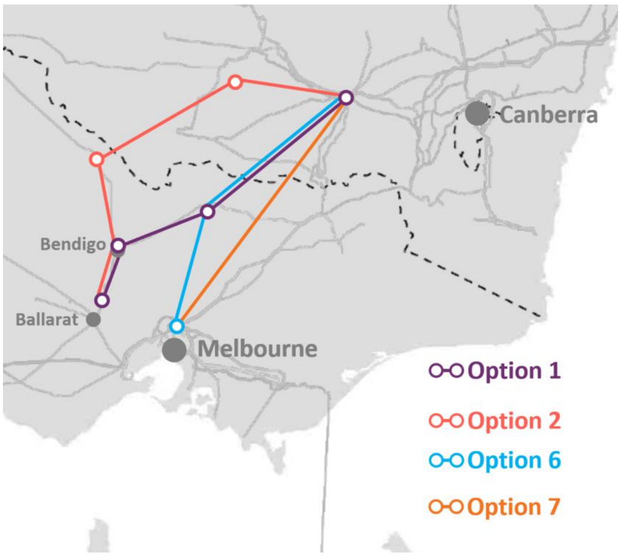
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 (HumeLink) • New 500 kV single-circuit from Maragle to Bannaby. • New 500 kV single-circuit from Maragle to Wagga Wagga. • New 500 kV single-circuit from Wagga Wagga to Bannaby. • Cut-in Lower Tumut to Upper Tumut 330 kV line at Maragle. • Three 500/330 kV 1,500 MVA transformers at Maragle. • Two 500/330 kV 1,500 MVA transformers at Wagga Wagga. • 500 kV Line shunt reactors at the ends of Maragle – Bannaby, Maragle – Wagga Wagga and Wagga Wagga – Bannaby lines. *Provided by TransGrid – see Section 1.1.*	2,200 MW in both directions REZ N6+N7: 2,200 MW	3,315	Unknown*	2026-27
Option 2 • An additional new 500 kV line between Wagga Wagga and Bannaby *Pre-requisite: HumeLink*	2,000 MW in both directions REZ N6: 1,500 MW	953	Class 5b (±50%)	Long
Option 3 – HVDC between Wagga Wagga and Bannaby:	2,000 MW in both directions	2,038	Class 5b (±50%)	Long

• A 2,000 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. *Pre-requisite: HumeLink*	REZ N6: 2,000 MW			

Adjustment factors and risk				
Option	**Adjustment factors applied**		**Known and unknown risks applied**	
Option 1 HumeLink	• Not provided by TransGrid			
Option 2	• Location: Regional • Land use: Grazing • Project size: Project size: 1-5 bays • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 100%	• Known risks: BAU • Environmental offset: High • Cultural heritage: High • Unknown risks: Class 5	• Market activity: Tight • Compulsory acquisition: High
Option 3	• Location: Regional • Land use: Grazing • Project size: applicable for HVDC converter station • Terrain: Hilly/undulating	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 100%	• Known risks: BAU • Environmental offset: High • Cultural heritage: High • Unknown risks: Class 5	• Market activity: Tight • Compulsory acquisition: High • Project complexity: Highly complex for converter station

* Estimates for costs for HumeLink and the New South Wales works on VNI West are included using TransGrid's estimates. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

3.9 Victoria to Southern New South Wales

Summary	
A RIT-T is in progress for a large new interconnector between Victoria and New South Wales (VNI West) by AEMO and TransGrid. The 2020 ISP recommended two preferred routes for VNI West – one via Kerang and one via Shepparton. Two additional options are identified that can be implemented after VNI West. These options enable high transfer between New South Wales and Victoria and provide access to renewable generation in Murray River, Central North Victoria and Western Victoria REZs.	
Existing network capability	
Transfer capability of future options will be modelled with VNI minor upgrade and 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 contingency at times of peak demand and typical summer periods.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: VNI West (Shepparton) • Two new 500 kV overhead lines from north of Ballarat to near Shepparton to locality of Wagga Wagga. • A new 500/220 kV terminal station with two 500/220 kV 1,000 MVA transformers near Shepparton. • A 220 kV double-circuit line from Shepparton terminal station to near Shepparton. • 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 North of Ballarat - near Shepparton, near Shepparton - locality of Wagga Wagga 500 kV circuits. • Up to ±400 megavolt-amperes reactive (MVAr) dynamic reactive compensation at the new 220 kV terminal station near Shepparton. *Provided by AEMO (Victorian Planning) and TransGrid – see Section 1.1.*	North: 1,930 MW South: 1,800 MW REZ V3: 550 MW REZ V6: 1050 MW	2,711 (combined cost from AEMO VIC Planning and TransGrid)	Unknown*	Long
Option 2: VNI West (Kerang)	North: 1,930 MW South: 1,800 MW	4,076 (combined cost from AEMO	Unknown*	Long

• Two new 500 kV overhead lines from north of Ballarat to near Bendigo to near Kerang to locality of Dinawan to locality of Wagga Wagga. • New substations near Bendigo and near Kerang. • Two 500/220 kV 1,000 MVA transformers at each of the new substations near Bendigo and Kerang. • Two 500/330 kV 1,500 MVA transformers in the locality of Dinawan. • 220 kV connections from the existing terminal station at Bendigo to new terminal station near Bendigo. • 220 kV connections from the existing terminal station at Kerang to new terminal station near Kerang. • 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 North of Ballarat - near Bendigo, near Bendigo - near Kerang, near Kerang - locality of Dinawan and locality of Dinawan - locality of Wagga Wagga 500 kV circuits. • Up to ±400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang. *Provided by AEMO (Victorian Planning) and TransGrid – see Section 1.1.*	REZ V2: 1,600 MW REZ V3: 550 MW	VIC Planning and TransGrid)		
Option 6: • A new 500 kV double-circuit line from north of Melbourne to near Shepparton to locality of Wagga Wagga. • A new 500 kV Terminal Station in north of Melbourne and near Shepparton. • Cut-in the existing South Morang–Sydenham 500 kV circuits at a new substation in north of Melbourne. • Two 500/220 kV 1,000 MVA transformers at a new terminal station near Shepparton. • A 500/330 kV transformer at Wagga Wagga. • Cut-in the Shepparton-Glenrowan line into the new station near Shepparton • Cut-in Rowville–Thomastown 220 kV line at South Morang. • Additional reactive plants at terminal stations in north of • Melbourne and near Shepparton and locality of Wagga Wagga. • A new ±300 MVAr dynamic reactive plant near Shepparton 220 kV. *Pre-requisite: VIC-SNSW Option 2 – VNI West Kerang*	North: 2,000 MW South: 1,500 MW REZ V6: 1,700MW	2,317	Class 5b (±50%)	Long
Option 7: • A 2,000 MW HVDC bi-pole overhead transmission line from north of Melbourne to locality of Wagga Wagga. • A new 2,000 HVDC bipole converter station in north of Melbourne. • A new 2,000 HVDC bipole converter station in locality of Wagga Wagga.	North: 2,000 MW South: 2,000 MW	2,510	Class 5b (±50%)	Long

• Connect both the existing South Morang-Sydenham 500 kV lines at the new terminal station in north of Melbourne. • AC network connection between HVDC converter station and the new terminal station in north of Melbourne. • AC network connection between HVDC converter station in locality of Wagga Wagga and the existing Wagga Wagga substation. • Cut-in Rowville–Thomastown 220 kV line at South Morang. *Pre-requisite: VIC-SNSW Option 1 or 2*				

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Options 1 and 2	Unknown*	
Option 6	• Location: Regional • Land use: Grazing • Project size: Project size: 6-10 bays • Terrain: Flat/farmland • Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 100%	• Known risks: BAU • Environmental offset: High • Cultural heritage: High • Unknown risks: Class 5 • Market activity: Tight • Compulsory acquisition: High • Outage restrictions: High
Option 7	• Location: Regional • Land use: Grazing • Project size: applicable for HVDC converter station • Terrain: Flat/farmland • Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 100%	• Known risks: BAU • Environmental offset: High • Cultural heritage: High • Unknown risks: Class 5 • Market activity: Tight • Compulsory acquisition: High • Outage restrictions: High • Project complexity 'highly complex'

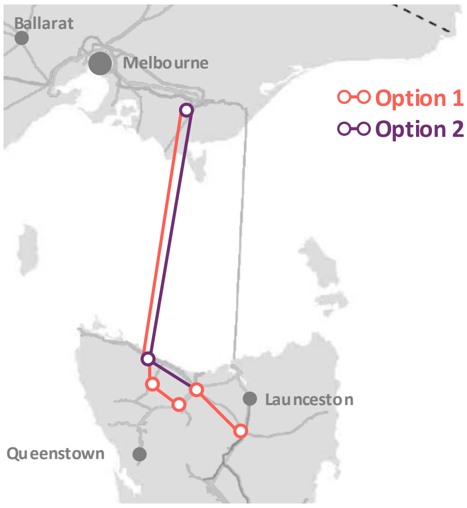
* Estimates for costs for HumeLink and the NSW works on VNI West are included using TransGrid's estimates. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

3.10 Tasmania to Victoria

Summary

Marinus Link is a proposal that consists of two new high voltage direct current (HVDC) cables connecting Tasmania to Victoria, each with 750 MW transfer capacity and associated high voltage alternating current (HVAC) transmission. TasNetworks is currently undertaking a RIT-T to identify the preferred option for the project. The PADR, the second report of the RIT-T, was published in December 2019. In November 2020, TasNetworks published a supplementary analysis report, with updated cost benefit analysis using the *2020 ISP* assumptions.

TasNetworks proposes to implement Marinus Link in two stages.



Existing network capability

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

Transfer capacity between Tasmania and Victoria is limited to 478 MW in both directions at times of peak demand, summer typical and winter reference periods.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 (Marinus Link – Stage 1) • A 750 MW monopole high voltage direct current (HVDC) link between Burnie area in Tasmania and Hazelwood area in Victoria. • Construction of a new 220 kV switching station at Heybridge adjacent to the converter station. • Establishment of a new 220 kV switching station at Staverton. • Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie. • A 220 kV double-circuit AC line from Palmerston to Sheffield. *Provided by TasNetworks – see Section 1.1.*	Marinus Link: 750 in both directions. Basslink and Marinus Link Stage 1 combined: TAS to VIC 1,228 VIC to TAS 978 REZ T2 or T3: 800 MW	Early works: 189 Project delivery: 2,081	Class 4 (±15%)	2027-28
Option 2 (Marinus Link – Stage 2) • A second 750 MW monopole HVDC link between Burnie area in Tasmania and Hazelwood area in Victoria. • Construction of 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. *Provided by TasNetworks – see Section 1.1.*	Marinus Link: 750 in both directions. Basslink and Marinus Link Stages 1 and 2 combined: TAS to VIC 1,978 VIC to TAS 1,728 REZ T2 or T3: 800 MW	1,210 (If completed within 3 years of Stage 1). 1,810 (If completed after 3 years of Stage 1)	Class 4 (±15%)	2029-30

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[28].	

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

4. Renewable energy zones

REZs are areas in the NEM where clusters of large-scale renewable energy can be efficiently developed, promoting economies of scale in high-resource areas, and capturing important benefits from geographic and technological diversity in renewable resources. The geographic boundaries, resource quality and existing transmission limits for each REZ were determined through the initial 2021 IASR consultation.

This chapter outlines network augmentation options to increase the network hosting capacity[29] of REZs. 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.

Section 2.4.6 of AEMO's *ISP Methodology*[30] provides an overview of how AEMO proposes using these augmentation options and costs in the ISP modelling.

4.1 Overview

REZ network augmentations are designed to allow connection of new generation to the existing network and overcome expected network congestion. The full list of candidate REZs considered for the 2022 ISP is shown in Figure 7.

Figure 8 highlights the allocation of costs associated with REZ network augmentation costs shown in this section, and delineates these from costs associated with generator connections. REZ network augmentations are designed to allow connection of new generation to the existing network and overcome expected network congestion.

Where network congestion can result due to the combined output from multiple REZs, grouped REZ network augmentation options are defined (see Section 4.3.10 and Section 4.4.10).

For any scenario where load centres may emerge near ports as described in Section 4.9.3 of the IASR[31], AEMO is proposing to use REZ network expansion costs based on those calculated for the Q9 Banana REZ.

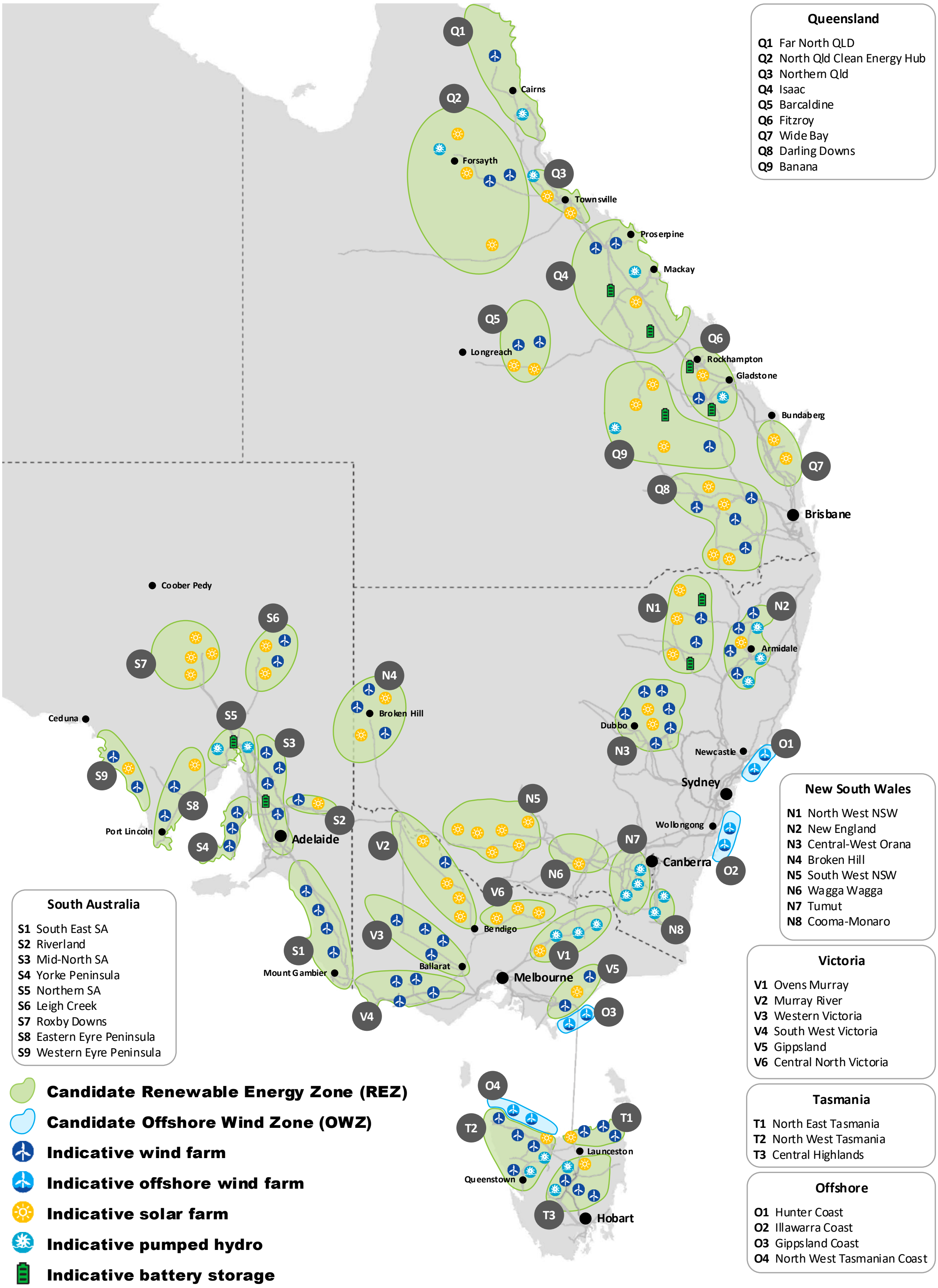
The following sections include tables that provide an overview of the characteristics of each network development option. Section 3.2 explains the terminology used in these tables.

[29] The "hosting capacity" of a REZ refers to the amount of generation that can be connected within the REZ and efficiently supplied to load centres.

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

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

Figure 7 Candidate renewable energy zones



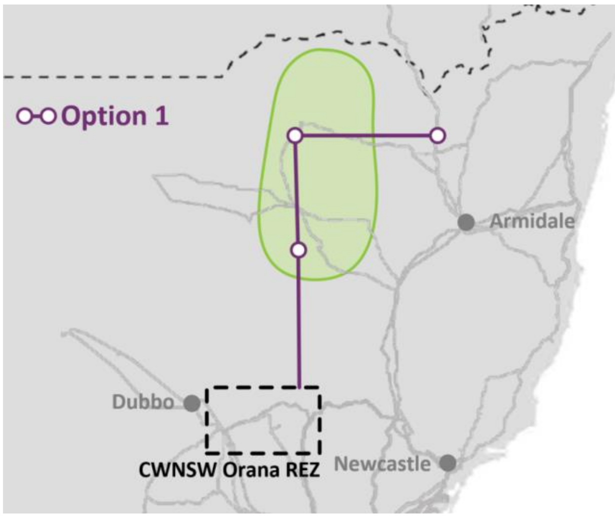
4.2 New South Wales

4.2.1 North West New South Wales (N1)

Summary

The North-West New South Wales (NWNSW) REZ is located to the west of the existing Queensland – New South Wales (QNI) interconnector. The capacity of this REZ is supported by QNI Medium and QNI Large upgrade proposals (see Section 3.5). While this zone has high quality solar resources, the wind resource is estimated to be inadequate for wind farm development.

As generation further increases in NWNSW and New England REZs, increased connection capacity between the two REZs is likely to 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 current hosting capacity of approximately 100 MW.

Augmentation options

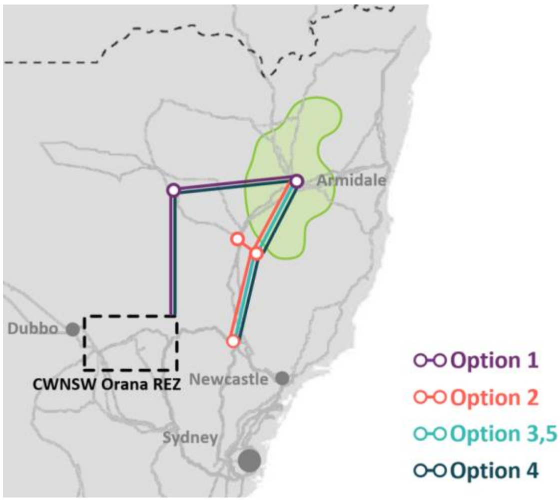
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1*: • Two new 500 kV circuits from Orana REZ to locality of Gilgandra to locality of Boggabri to locality of Moree. • A new single 500 kV circuit from Orana REZ to Wollar. • New 500/330 kV substations 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. • Two ±300 MVAr SVCs *Scope provided by TransGrid and costed by AEMO – see Section 1.1.*	1,660	3,584	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location: Remote • Land use: Grazing • Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Unknown risks: Class 5 • Compulsory Acquisition: High • Environmental Offset: High • Market Activity: Tight

* AEMO requested that TransGrid provide information on these options through preparatory activities as per NER clause 5.22.6(c). Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

4.2.2 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 QNI Medium and QNI Large upgrade proposals.† 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. As generation further increases in North West New South Wales and New England REZs, increased connection capacity between the two REZs is likely to 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 network capacity, following completion of the committed QNI minor upgrade (see Section 3.5), 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

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: ‡ • A new 500 kV double-circuit from locality of Armidale South to locality of Boggabri to Orana REZ. • A new single 500 kV circuit from Orana REZ to Wollar. • A new 500/330 kV substation in locality of Armidale South. • A new 500 kV switching station in locality of Boggabri • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. *Scope provided by TransGrid and costed by AEMO – see Section 1.1.*	1,295	2,279	Class 5b (±50%)	Long
Option 2: ‡ • A new 500 kV double-circuit line from locality of Armidale South to Bayswater via east of Tamworth • A new 500/330 kV substation in locality of Armidale South. • A new 500/330 kV substation in locality of east of Tamworth. • A new 330 kV circuit from the locality of east of Tamworth to Tamworth. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 330 kV from Armidale to the locality of Lower Creek *Scope provided by TransGrid and costed by AEMO – see Section 1.1.*	1,800	2,009	Class 5b (±50%)	Long

Option 3: • A new 330 kV double-circuit line from south of Armidale to Liddell. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South.	1,590	891	Class 5b (±50%)	Long
Option 4: • A new 500kV single-circuit from Bayswater to locality of Armidale South to locality of Boggabri to Orana REZ. • A new single 500 kV circuit from Orana REZ to Wollar. • A new 500/330 kV substation in locality of Armidale South. • A new 500 kV switching station in locality of Boggabri • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 500 kV line shunt reactors at Bayswater, locality of Armidale South, locality of Boggabri, Orana REZ and Wollar.	1,800	2,316	Class 5b (±50%)	Long
Option 5: • 2,000 MW bi-pole HVDC transmission system between Bayswater and locality of Armidale South. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth-Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South	2,000	2,162	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied		Known and unknown risks applied	
Options 1 and 2	• Location: Remote • Land use: Grazing • Delivery timetable: Long • Total circuit length: above 200 km	• Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Compulsory Acquisition: High • Environmental Offset: High • Market Activity: Tight	• Unknown risks: Class 5
Options 3 and 4	• Location: Remote • Land use: Grazing • Project size: Project size: 1-5 bays	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Compulsory Acquisition: High • Environmental Offset: High • Market Activity: Tight	• Unknown risks: Class 5
Option 5	• Location: Remote • Land use: Grazing • Project size: applicable for HVDC converter station	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Unknown risks: Class 5	• Project complexity: Highly complex

† Options shown are a subset of the Central New South Wales to Northern New South Wales flow path options, described in Section 3.6.

‡ AEMO requested that TransGrid provide information on these options through preparatory activities as per clause 5.22.6(c) in NER. Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

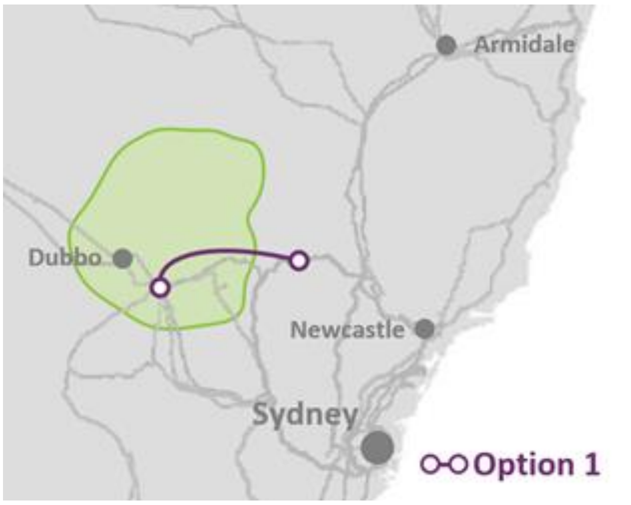
4.2.3 Central West Orana (N3)

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†. The *NSW Electricity Infrastructure Investment Act 2020* legislates the REZ be declared with an intended 3,000 MW of additional transmission network capacity within the Central-West Orana region of the state.

Due to the nature of the project, which is currently going through consultation on corridor selection, specific information on the project is not able to be provided, but it is expected to include new transmission lines connecting to a 500 kV and 330 kV loop in the vicinity of the Central-West Orana REZ indicative location.



Note: The transmission study corridor is currently under consultation. More information is available at https://energy.nsw.gov.au/renewables/renewable-energy-zones.

Existing network capability

The project to establish the Central West Orana REZ is considered anticipated, and as such the existing network capability is approximately 3,900 MW

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Options to be considered within the bounds of the anticipated project include: • New transmission lines connecting to 500 kV and 330 kV network in vicinity of the Orana REZ indicative location.	*Anticipated Project (See Section 1.1)*			

† See https://energy.nsw.gov.au/renewables/renewable-energy-zones#-centralwest-orana-renewable-energy-zone-pilot-.

4.2.4 Broken Hill (N4)

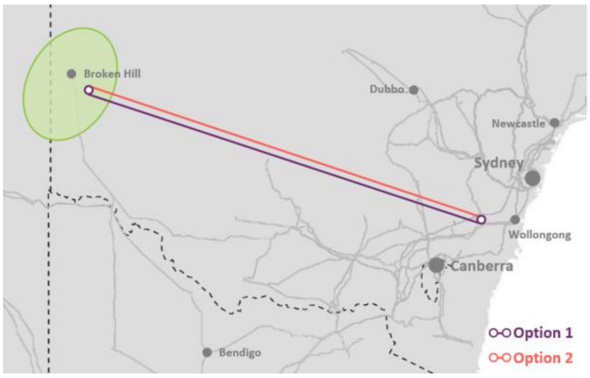
Summary

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 large-scale solar and wind generation projects already operating in this REZ, there is no additional hosting 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	4,004	Class 5b (±50%)	Long
Option 2: • Bipole HVDC transmission from Bannaby – Broken Hill (>850 km).	1,750	3,750	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Project network element size: Above 200 km, no. of total bays above 31 / applicable for HVDC converter station project • Location (regional/distance factors): Remote (except Bannaby which is Regional) • Land use: Grazing • Proportion of environmentally sensitive areas: 0%	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Delivery timetable: Long • Project network element size: Above 200 km, no. of total Bays above 31 / applicable for HVDC converter station project • Land use: Grazing • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU • Unknown risks: Class 5 • Project complexity: Partly complex line work and Highly complex for converter stations

4.2.5 South West NSW (N5)

Summary

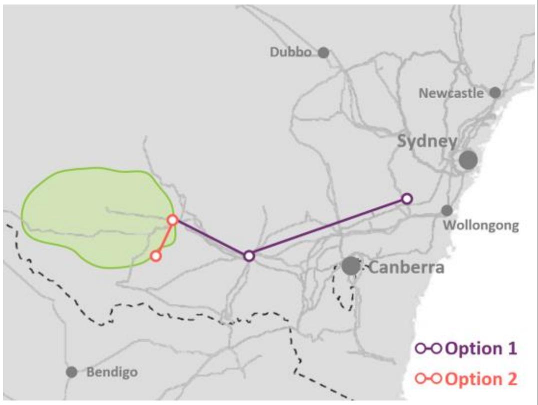
The South West REZ has good solar resource and incorporates the Darlington Point substation which marks the transition from 330 kV to 220 kV. Further west, the 220 kV links to North West Victoria and Broken Hill.

This REZ is one of three REZs which are being targeted for further development under the NSW Electricity Infrastructure Roadmap.

Existing network capability

Due to the existing large-scale solar projects already operating within this REZ, there is no additional hosting 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 (see Section 1.1) and HumeLink (see Section 3.8) projects. Furthermore, one option for VNI West (Kerang route) would also increase the hosting capacity of this REZ (see Section 3.9).



Augmentation options

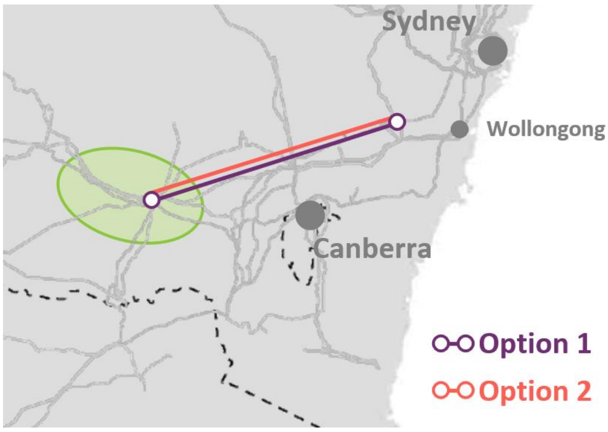
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Rebuild 330 kV Darlington Point – Wagga to a high capacity double-circuit line. • 500 kV single-circuit line from Bannaby – Wagga. • 500/330 kV 1,500 MVA transformer at Wagga.	1,500	1,416	Class 5b (±50%)	Long
Option 2: • Establish a new Darlington Point to Dinawan 330 kV transmission line. ‡	600	*185* †	Unknown	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Project network element size: Above 200 km, no. of bays 11-15 • Location (regional/distance factors): Regional • Land use: Grazing • Proportion of environmentally sensitive areas: 0%	• Known risks: BAU • Decommissioning not costed • Unknown risks: Class 5
Option 2	• Cost estimate provided by TransGrid	• Cost estimate provided by TransGrid

† The cost presented in TransGrid's RIT-T was $145-225 million.
‡ Improving stability in south-western NSW RIT-T – Project Specification Consultation Report, TransGrid, 30 July 2020, at https://transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf.

4.2.6 Wagga Wagga (N6)

Summary	
This REZ extends to the west of Wagga Wagga, and has moderate wind and solar resources.	
Existing network capability	
There is no additional hosting capacity within this REZ. 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 is 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: • 500 kV double-circuit line from Bannaby – Wagga. • Two 500/330 kV 1,500 MVA transformers at Wagga.	2,600	1,229	Class 5b (±50%)	Long
Option 2: • 500 kV single-circuit line from Bannaby – Wagga. • One 500/330 kV 1,500 MVA transformer at Wagga.	1,500	950	Class 5b (±50%)	Long

Adjustment factors and risk

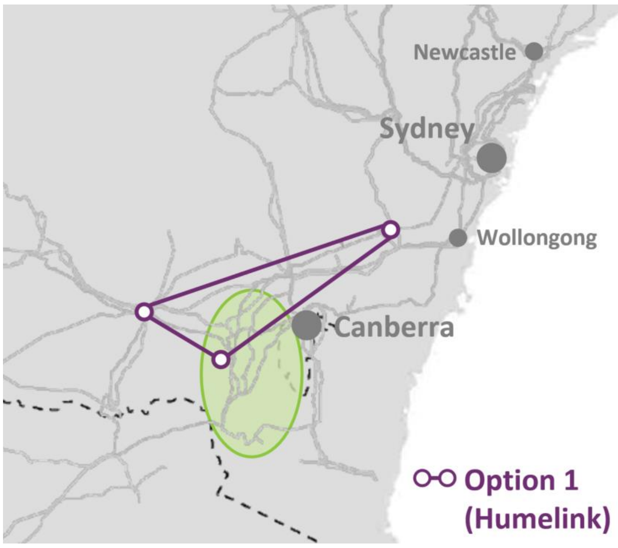
Option	Adjustment factors applied	Known and unknown risks applied
Option 1 and 2	• Delivery timetable: Long • Land use: Grazing • Project network element size: Above 200 km, no. of bays 11-15 for Option 1 and 6-10 for Option 2 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional	• Known risks: BAU • Unknown risks: Class 5

4.2.7 Tumut (N7)

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 (see Section 3.8).

The HumeLink project which is currently undergoing a RIT–T [32] 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 hosting 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
HumeLink (Actionable ISP 2020 project – see Section 3.8)	2,200 (SNSW to CNSW)	See Section 3.8.		

Adjustment factors and risk

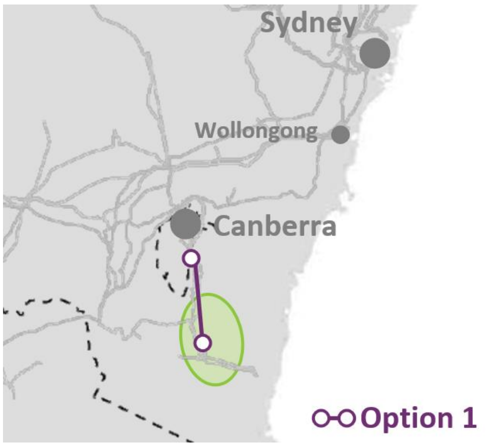
Option	Adjustment factors applied	Known and unknown risks applied
HumeLink	See Section 3.8.	

[32] See https://www.transgrid.com.au/humelink.

4.2.8 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	140	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: Above 10-100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional	• Known risks: BAU • Unknown risks: Class 5

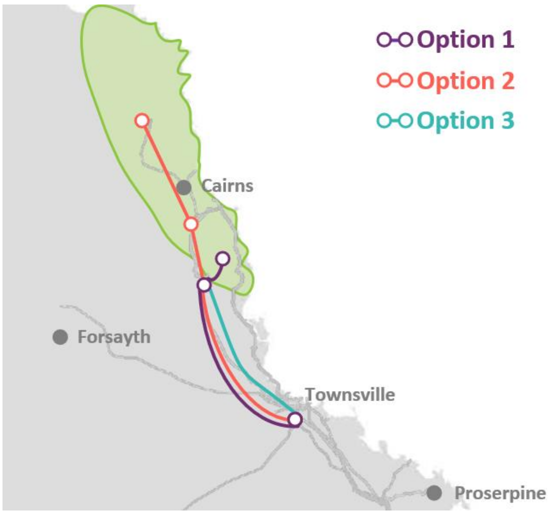
4.2.9 Hunter Central Coast and Illawarra

Summary
The New South Wales Government is in the early stages of planning for two new REZs in the Hunter-Central Coast and Illawarra regions of New South Wales, as set out under the *NSW Electricity Infrastructure Act 2020*†. The New South Wales Government is in the early stages of planning the geographic area and network design and as such network augmentation options are not yet developed.
Existing network capability
To be determined at a later date.

† See https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044#statusinformation.

4.3 Queensland

4.3.1 Far North Queensland (Q1)

Summary	
The Far North Queensland (FNQ) REZ is at the most northerly section of Powerlink's network. It has excellent wind and moderate solar resources and has existing hydroelectric power stations. Four options are proposed that progressively increase network capacity, and allow for upgrades based on where generation develops.	
Existing network capability	
Maximum export capability from the FNQ REZ is limited by voltage stability for a contingency of a Ross to Chalumbin 275 kV circuit. The existing network will allow for a total of approximately 750 MW of VRE to be connected. Output from this REZ can also be limited by network capacity further south which can result in the need for additional network augmentations. Output from this REZ is included in the NQ1, NQ2 and NQ3 Group Constraints (see section 4.3.10) to take this into account. Powerlink has also recently announced plans for upgrades to transmission networks in the Q1 REZ as part of the Northern Queensland Renewable Energy Zone[33]. AEMO considers this to be an anticipated project (see Section 1.1).	

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 string and energise as a single-circuit line.	945	1,264	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).	945	1,893	Class 5b (±50%)	Long

[33] Powerlink. *Queensland Renewable Energy Zones*, at https://www.powerlink.com.au/queensland-renewable-energy-zones.

• Build additional Chalumbin-Ross 275 kV double-circuit tower but string and energise as a single-circuit line.				
Option 3: • String and energise the other Chalumbin-Ross 275 kV additional circuit. *Pre-requisite: Option 1 or 2.*	345	155	Class 5b (±50%)	Medium

Adjustment factors and risk

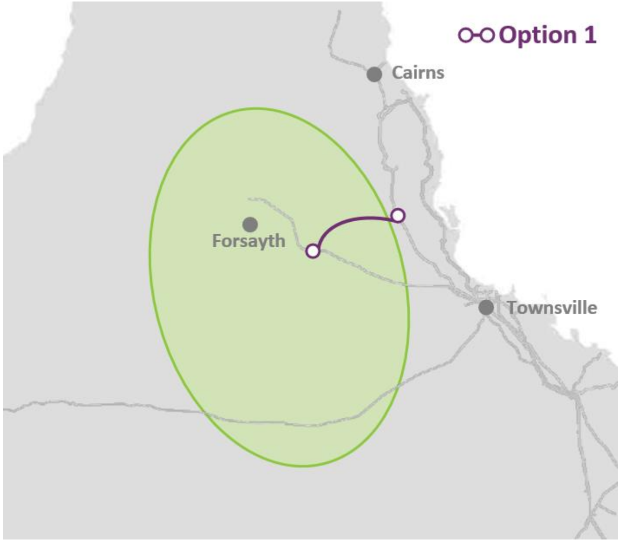
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Estimated 75% proportion of project in environmentally sensitive areas • 'Remote' location for substation near Lakeland • Total circuit length 'above 200 km', project size 1 – 5 bays	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Estimated 75% proportion of project in environmentally sensitive areas • 'Regional' location for Millstream Substation • Total circuit length 'above 200 km', project size 1 – 5 bays	• Known risks: BAU • Unknown risks: Class 5
Option 3	• 'Regional' location for circuit • Total circuit length 'above 200 km', project size 1 – 5 bays	• Known risks: BAU • Unknown risks: Class 5

4.3.2 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.

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



Existing network capability

Currently the REZ is supplied via a 132 kV line from Ross. Interest in this area includes the development of Kidston pumped storage project which Powerlink has recently received a 'Notice to Proceed' to develop a single-circuit 275 kV line†.

Output from this REZ can also be limited by network capacity further south which can result in the need for additional network augmentations. Output from this REZ is included in the NQ1, NQ2 and NQ3 group constraints (see Section 4.3.10).

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build additional 275 kV single-circuit line from Kidston Substation to midpoint switching station	500	410	Class 5a (±30%)	Long

Adjustment factors and risk

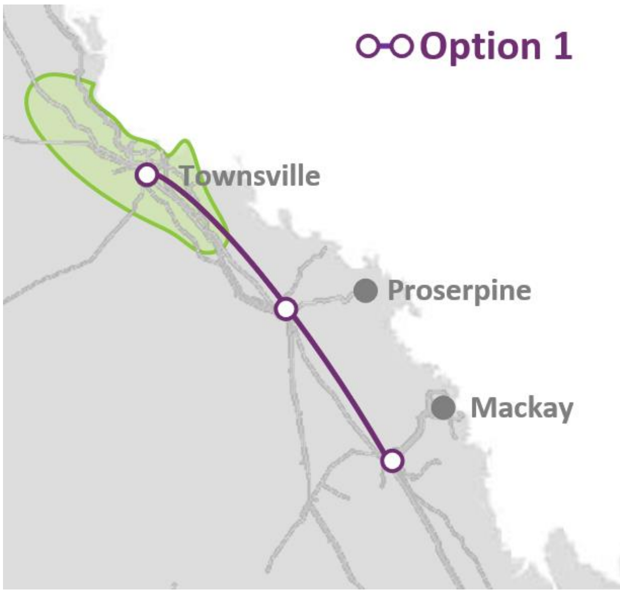
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• 'Remote' location for Kidston Substation in 'Desert' environment. • Total circuit length '150 - 200 km', project size 1-5 bays • Circuit built at cyclone standard	• Known risks: BAU • Unknown risks: Class 5

† Powerlink, Genex-Kidston connection project, at https://www.powerlink.com.au/projects/genex-kidston-connection-project.

4.3.3 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.



Existing network capability

Due to the existing high voltage infrastructure there are no augmentation options specifically for this REZ. Existing network capacity can allow for up to approximately 1,200 MW of new generator connections, shared between Q1, Q2 and Q3.

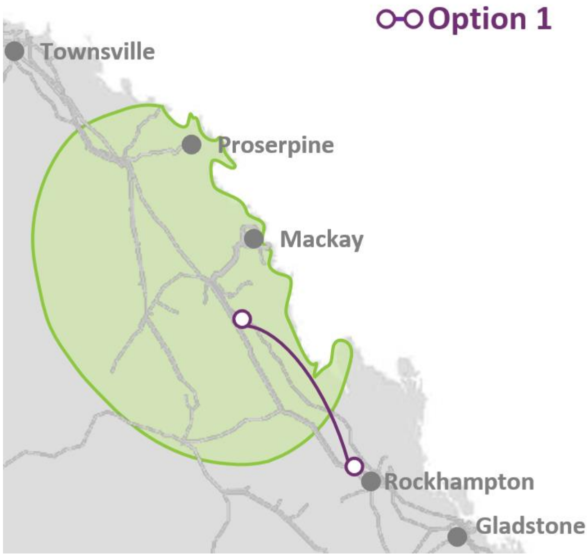
Output from this REZ can be limited by network capacity further south which can result in the need for additional network augmentations. Output from this REZ is included in the NQ1, NQ2 and NQ3 group constraints (see Section 4.3.10).

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.3.10 (NQ1).				

4.3.4 Isaac (Q4)

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>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.

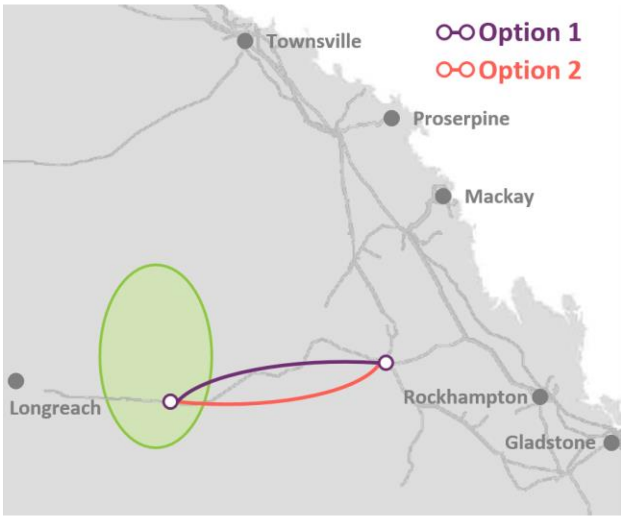
There are numerous potential pumped hydro locations to the north east and south east of Nebo. This REZ has a good diversity of resources – wind, solar and storage. Locating storage in this zone could maximise transmission utilisation towards Brisbane.</td><td rowspan="4">
</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>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 across the REZs in northern Queensland, depending on the level of storage in these REZs.</td></tr>
</table>

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.3.10 (NQ2 and NQ3).				

4.3.5 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	
This REZ is fed via a 132 kV line from Lilyvale. A total of 100 MW of inverter-based generation is already installed on this long radial 132 kV network. Currently there is no spare network capacity available within the Barcaldine REZ. Output from this REZ can be limited by network capacity further south which can result in the need for additional network augmentations. Output from this REZ is included in the NQ2 and NQ3 group constraints to take this into account (see Section 4.3.10).	

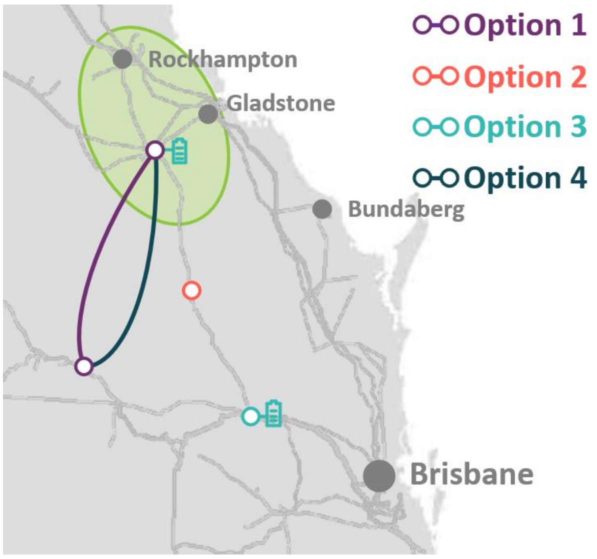
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: (Single-circuit) • Establish a 275 kV substation in the Barcaldine region • Build a 300 km 275 kV single-circuit line on double-circuit towers from Lilyvale to Barcaldine.	500	742	Class 5b (±50%)	Long
Option 2: (Double-circuit) • String the second circuit on the towers established in Option 1. • Additional substation bays and reactors. *Pre-requisite: Option 1*	1,000	208	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1: Single-circuit	• 'Remote' location for Barcaldine Substation in 'Desert' environment. • Total circuit length '200 km+', project size 1 – 5 bays • Circuit built at cyclone standard	• Known risks: BAU • Unknown risks: Class 5
Option 2: Double-circuit	• 'Remote' location for Kidston Substation in 'Desert' environment. • Total circuit length '200 km+', project size 1 – 5 bays • Circuit built at cyclone standard	• Known risks: BAU • Unknown risks: Class 5

4.3.6 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	
The network has the ability to support up to 2,100 MW of power transfer from Central Queensland to Southern Queensland which is defined as the transient stability limit of the network (for a contingency of Calvale–Halys 275 kV circuit). Due to the existing high voltage infrastructure, there are no augmentation options specifically for this REZ. The associated augmentations are the NQ3 group constraint augmentations that facilitate power from Q1 to Q6 to be transmitted south to the load centres (see Section 4.3.10).	

Augmentation options

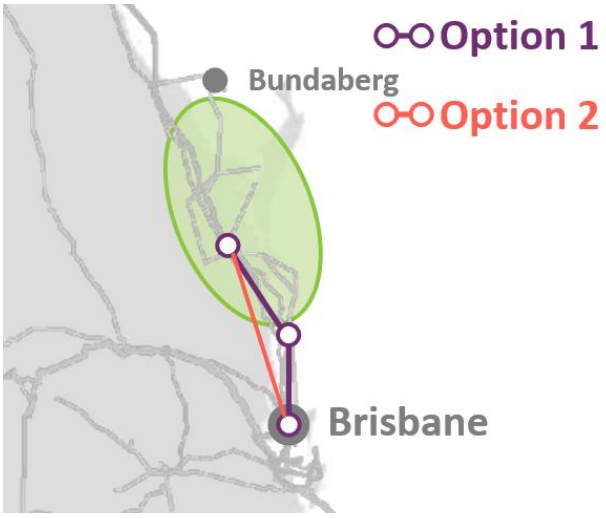
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
See Section 4.3.10 (NQ3).				

4.3.7 Wide Bay (Q7)

Summary

The Wide Bay area has moderate solar resources and already has a number of large solar PV generators operational within the REZ.

There is difficultly getting easements in this residential area, and hence this would require a rebuild of the existing single -circuit lines as double-circuits to help reduce those challenges around obtaining easements should the generation interest exceed the current network capacity.



Existing network capability

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 500 MW of generation connecting in the area north of Brisbane up to Gympie.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Rebuild Woolooga – Palmwoods – South Pine 275 kV single-circuit line as a high capacity double-circuit line • 100 MVAr reactor for voltage control	900	473	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	900	443	Class 5b (±50%)	Long

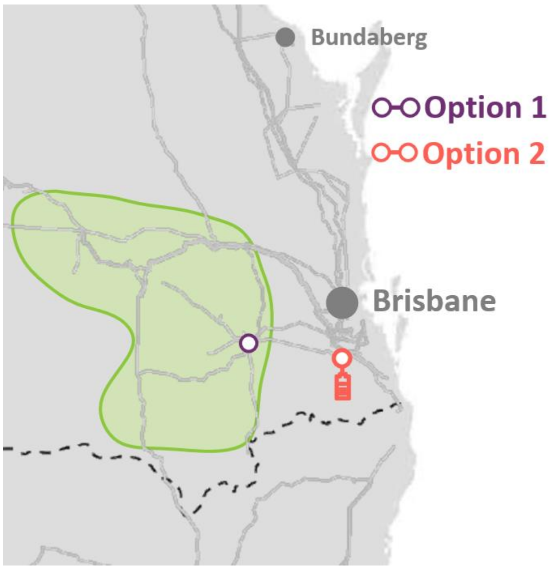
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Circuit terrain: Hilly/undulating • Total Circuit length: < 200 km • Land Use: Regional	• Known risks: BAU • Unknown risks: Class 5 • Line decommissioning costs not included
Option 2	• Circuit terrain: Hilly/undulating • Total Circuit length:< 200 km • Land Use: Regional	• Known risks: BAU • Unknown risks: Class 5 • Line decommissioning costs not included

4.3.8 Darling Downs (Q8)

Summary

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.



Existing Network Capability

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.

Under high demand conditions, this corridor can only facilitate 1,300 MW into the greater SEQ area from generation connected around the Bulli Creek area. Generation connected around Halys area will be required to allow the full 3,000 MW REZ capacity to be able to be utilised. The Middle Ridge site is very constrained – further investigation is required to determine the feasibility of any expansion of this substation.

Augmentation options

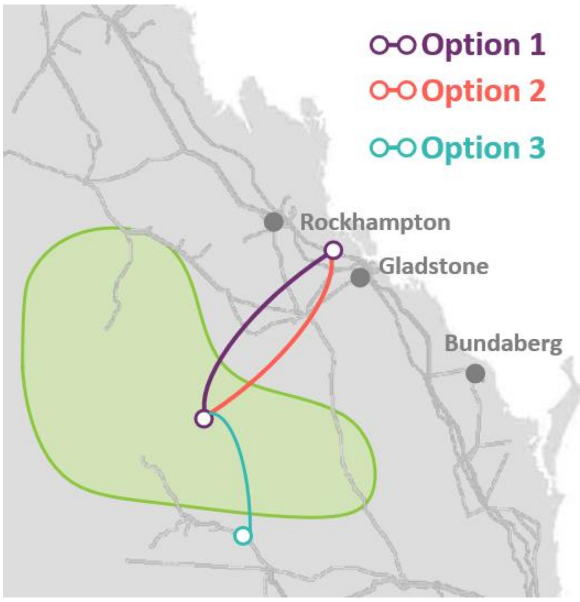
Description	Additional network capacity into SEQ (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Replace existing 1,300 MVA 330/275 kV transformer at Middle Ridge with 1,500 MVA 330/275 kV transformer. • Implement a post-contingent bus-splitting scheme at Middle Ridge.	500	43	Class 5b (±50%)	Medium
Option 2: • Replace existing 1,300 MVA 330/275 kV transformer at Middle Ridge with 1,500 MVA 330/275 kV transformer. • Implement a post-contingent bus-splitting scheme at Middle Ridge and a Special Protection scheme involving 300 MW SEQ BESS and generation runback within Q8 REZ.	800	43 + BESS costs to be provided by interested parties	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location: Regional	• Known risks: Outage restrictions 'High' • Unknown risks: Class 5
Option 2	• Circuit terrain: Hilly/undulating • Total Circuit length: < 200 km • Location: Regional	• Known risks: Outage restrictions 'High' • Unknown risks: Class 5
Option 3	• Circuit terrain: Hilly/undulating • Total Circuit length: < 200 km • Location: Regional	• Known risks: • Outage restrictions: High • Project complexity: Partly complex • Unknown risks: Class 5

4.3.9 Banana (Q9)

<table>
<tr><th colspan="2">Summary</th></tr>
<tr><td>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.</td><td rowspan="3">
</td></tr>
<tr><th>Existing network capability</th></tr>
<tr><td>There is very little high voltage network in the area currently. There is some low capacity 132 kV network on the edge of the REZ to support the townships of Moura and Biloela.

There is very little spare capacity within the current network which doesn't extend very far into the REZ. There is no easy way to reach the high voltage network or the Gladstone load.

Output from this REZ for options 1 and 2 will also be included in the NQ3 group constraint augmentations that facilitate power from Q1 to Q6 to be transmitted south to the load centres (see Section 4.3.10 (NQ3)).</td></tr>
</table>

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: 500 kV option • Establish a new 500 kV substation within the Banana REZ. • Establish a new 500 kV substation near Gladstone. • 200 km double-circuit 500 kV line from the Banana REZ to Gladstone. • Three 500/275 kV 1,500 MVA transformers near Gladstone. • Switchgear at the existing Gladstone substation. • Connection from Gladstone to the new Gladstone substation. *Note: This option is used as the generic REZ augmentation to connect REZs to hydrogen export ports†. This is expressed as a $/MW/km to suit different distances. Using Option 1 this generic cost works out at $1,833/MW/km.*	3,000	1,092	Class 5b (±50%)	Long
Option 2: 275 kV option • Establish a new 275 kV substation within the Banana REZ. • 200 km double-circuit 275 kV line from Banana REZ to Gladstone. • Switchgear at Gladstone.	1,000	557	Class 5b (±50%)	Long

Option 3: 275 kV option to Wandoan South • 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	541	Class 5b (±50%)	Long

Adjustment factors and risk		
Option	• Adjustment factors applied	• Known and unknown risks applied
Option 1	• Estimated 25% proportion of project in environmentally sensitive areas • 'Remote' location for Banana REZ Substation • Total circuit length 'above 200 km', in non-cyclone region (south of Bouldercombe).	• Known risks: Project Complexity was judged as partly complex due to no 500 kV network yet built in the Queensland region • Unknown risks: Class 5
Option 2	• Estimated 25% proportion of project in environmentally sensitive areas • 'Remote' location for Banana REZ Substation • Total circuit length 'above 200 km', in non-cyclone region (south of Bouldercombe).	• Known risks: BAU • Unknown risks: Class 5
Option 3	• Estimated 25% proportion of project in environmentally sensitive areas • 'Remote' location for Banana REZ Substation • 'Brownfield' work for Wandoan South connection • Total circuit length '100 – 200km', in non-cyclone region (south of Bouldercombe).	• Known risks: BAU • Unknown risks: Class 5

† The assumptions relating to REZ expansions for hydrogen export are described in AEMO's 2021 IASR; see Section 4.14, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

4.3.10 Queensland Group Constraints

Due to the long, unmeshed nature of the Queensland network, group constraints are the augmentations that are required to facilitate the transmission of power from isolated REZs (mostly in northern Queensland) to load centres in the south. They are not directly linked with the builds of a specific REZ, but rather the augmentations needed further into the network that are required due to the combined output from a number of REZs.

NQ1 Facilitating power out of North Queensland

Summary	
Upgrade options associated with the Group Constraint NQ1 may be built when total generation in Q1 + Q2 + Q3 (North Queensland) exceed 2,200 MW. This augmentation facilitates transmission from North Queensland to load centres in Central and Southern Queensland.	
Existing network capability	
The current network was designed to facilitate the transmission of power from Central Queensland to supply load in Northern Queensland. The network has the ability to support up to 2,200 MW of generation across the three REZs in North Queensland depending also on the level of storage in these REZs.	

Augmentation options

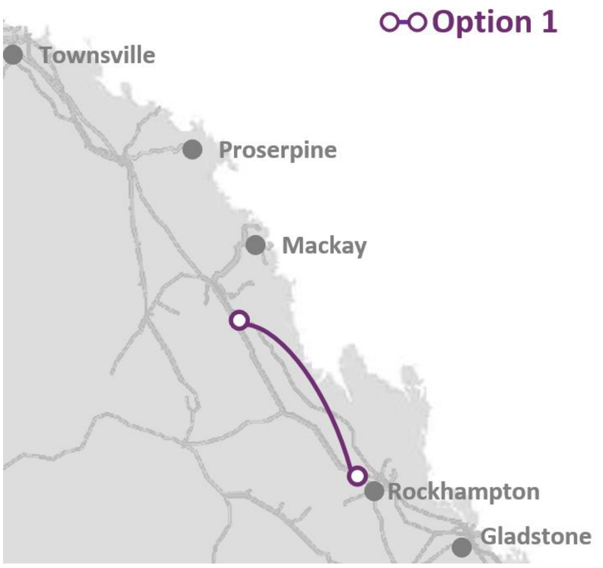
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Construct an additional circuit from Ross to Strathmore to Nebo.	740	801	Class 5b (±50%)	Medium

Adjustment factors and risk

Option	• Adjustment factors applied	• Known and unknown risks applied
Option 1	• Estimated 25% proportion of project in environmentally sensitive areas • 'Regional' location chosen • Total circuit length 'above 200 km', in cyclone region.	• Known risks: BAU • Unknown risks: Class 5

† Cost based on estimate provided by Powerlink for *2020 ISP*.

NQ2 Facilitating power to Central Queensland

Summary	
Upgrade options associated with the Group Constraint NQ2 may be built when generation in Q1 to Q5 (Northern Queensland) exceeds 2,500 MW. This is in order to facilitate transmission of this generation to load centres in the south. This group constraint is associated with the CQ-NQ intraregional connection.	
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. As such, the network has the ability to support up to 2,500 MW of generation across the five REZs in Northern Queensland depending also on the level of storage in these REZs.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Construct additional 275 kV circuit from Bouldercombe to Stanwell. • String and energise the second Broadsound-Stanwell 275 kV additional circuit (on existing DCST).	400	37	Class 5b (±50%)	Long

Adjustment factors and risk

Option	• Adjustment factors applied	• Known and unknown risks applied
Option 1	• Estimated 25% proportion of project in environmentally sensitive areas • 'Regional' location chosen • Total circuit length 'above 200 km', in cyclone region.	• Known risks: BAU • Unknown risks: Class 5

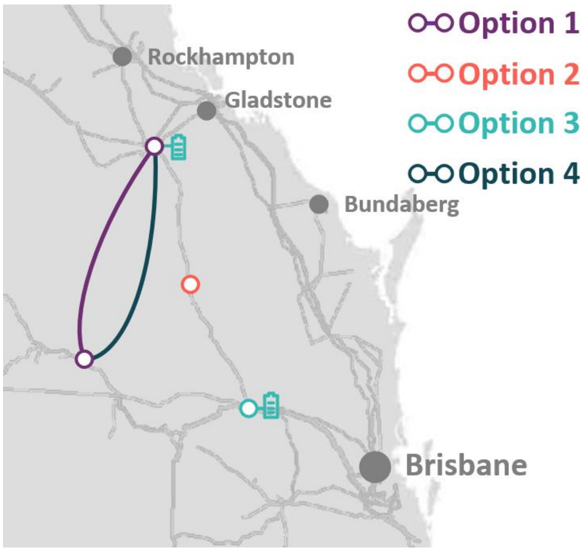
NQ3 Facilitating power to Southern Queensland

Summary

Upgrade options associated with the Group Constraint NQ2 may be built when export of over 2,100 MW of generation from Central and Northern Queensland to Southern Queensland is required.

The existing limit is defined by the transient stability level rather than a thermal limit as the associated circuits are long (over 300 km).

This group constraint is associated with the CQ-SQ intraregional constraint, and takes into account the output from Q1-Q6, as well as Q9.



Existing network capability

The current network was designed to facilitate the transmission of power from Central Queensland to support the load in Southern Queensland. The network has the ability to support up to 2,100 MW of power transfer from Central Queensland to Southern Queensland which is defined as the transient stability limit of the network prior to a contingency of Calvale–Halys 275 kV circuit.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1*: • Construct a 275 kV double-circuit line from Calvale – Wandoan South. *Provided by Powerlink – see Section 1.1.*	900	476	Class 5 (±75%)	Long
Option 2: • Mid-point switching substation on the Calvale – Halys 275 kV double-circuit line.	300	55	Class 5a (±30%)	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	*To be provided by interested parties*		
Option 4: • 1,500 MW bipole HVDC and overhead line between Calvale and South West Queensland	1,500	1,615	Class 5b (±50%)	Long

Adjustment factors and risk

Option	• Adjustment factors applied		• Known and unknown risks applied	
Option 1	• Refer to Powerlink's Preparatory Activities CQSQ Transmission Link report*.			
Option 2	• Location: Regional • Proportion of environmentally sensitive areas: 50%	• Land use: Scrub • Delivery timetable: Optimum • Project size: 1-5 bays	• Known risks: BAU • Unknown risks: Class 5	• Outage restrictions: High

Option 3	*Pending information from interested parties.*			
Option 4	• Location: Remote • Land use: Grazing • Project size: applicable for HVDC converter station	• Delivery timetable: Long • Total circuit length: above 200 km • Proportion of environmentally sensitive areas: 50%	• Known risks: BAU • Unknown risks: Class 5	• Project complexity: Highly complex

* See AEMO's IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

4.4 South Australia

4.4.1 South East SA (S1)

Summary	
The South East South Australia REZ lies on the major 275 kV route of the South Australia-Victoria Heywood interconnector. The REZ has moderate to good quality wind resources as it evidenced by the high proportion of wind generation (over 300 MW) in near the South East border with Victoria.	
Existing network capability	
There is currently no additional network hosting capacity available in this REZ without further augmentation. Network augmentations would be smaller if generation is located relatively close to Adelaide, and larger if located further south towards Mount Gambier.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • String vacant circuit on the 275 kV Tungkillo – Tailem Bend line. • 100 MVAr SVC at Tailem Bend • Assumes following NCIPAP project in place: • Turn in 275 kV circuit Tailem Bend to Cherry Gardens at Tungkillo†.	600	57	Class 5a (±30%)	Medium
Option 2: • 500 kV double-circuit line connecting South East to Heywood.	1,500 ‡	571	Class 5b (±50%)	Long

Adjustment factors and risk

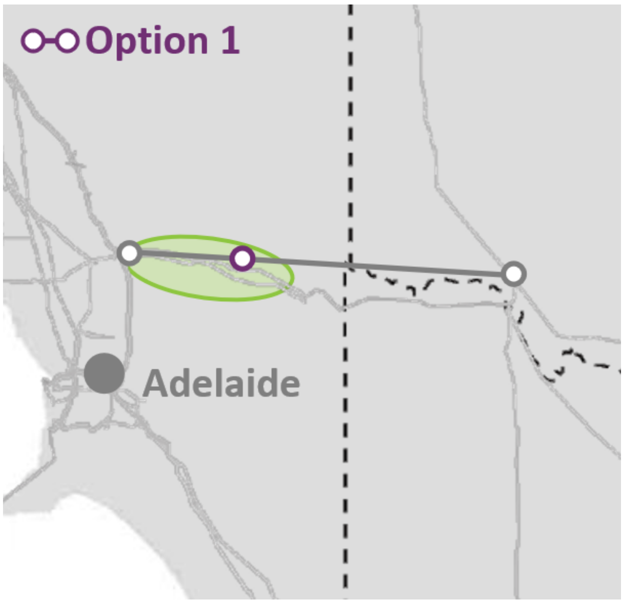
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Medium • Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional	• Known Risks: BAU. Low offset for Compulsory acquisition, Cultural heritage, Environmental offset risks, Geotechnical findings as not relevant to overall project scope • Unknown risks: Class 5
Option 2	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional	• Known risks: BAU • Unknown risks: Class 5

† 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. Hence, the cost for this component is not included in the expected cost. This project is complimentary to Option 1 and assists in realising the network capacity.
‡ Additional network capacity is realised for export flows from South Australia to Victoria via the South East to Heywood 500 kV lines.

4.4.2 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. 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): • Turn Bundey – Buronga 330 kV No. 1 and No. 2 lines into a new substation at Riverland.	700	77	Class 5a (±30%)	Medium

Adjustment factors and risk

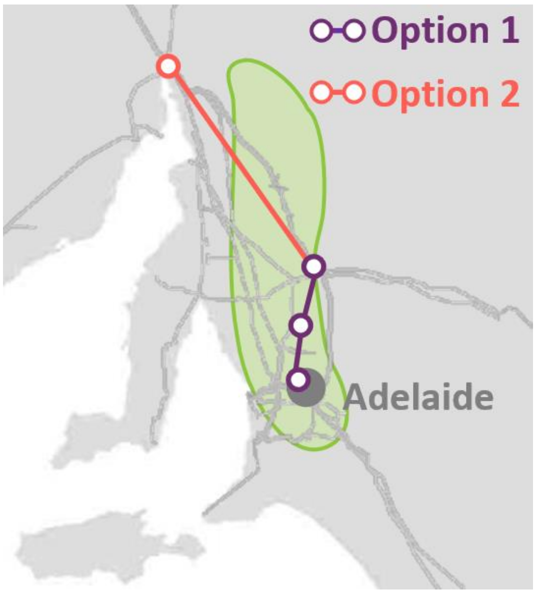
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: Below 1 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU, Outage restrictions: High • Unknown risks: Class 5

4.4.3 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

This REZ can accommodate approximately 1,000 MW of generation along the 275 kV corridor. However, due to the network configuration, any generation north and west of this REZ also contributes to this 1,000 MW limit. For this reason, an aggregate limit for South Australia of 1,000 MW applies to S3, S4, S5, S6, S7, S8 and S9 (see MN1 Group Constraint in Section 4.4.10).

Augmentation options

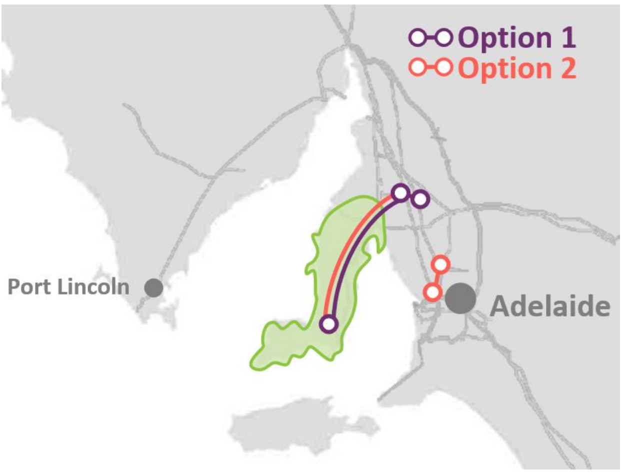
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1 • 275 kV double-circuit lines between Robertstown, Templers West and Para.	950†	340	Class 5b (±50%)	Long
Option 2 • 275 kV double-circuit lines between Davenport and Robertstown.	950	582	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional • Terrain: Flat/farmland (except Para to Templers West which is Hilly/undulating)	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Delivery timetable: Long • Land use: Grazing • Project network element size: Above 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote • Terrain: Flat/farmland	• Known risks: BAU • Unknown risks: Class 5

† Additional network hosting capacity is South of Robertstown towards Adelaide. This option does not alleviate the MN1_SA group constraint.

4.4.4 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 no additional network capacity. Transmission augmentation is required to connect any significant additional generation in this REZ. S4 is part of the MN1 Group Constraint† (see Section 4.4.10).	

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	443	Class 5b (±50%)	Long
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	202	Class 5b (±50%)	Long

Adjustment factors and risk

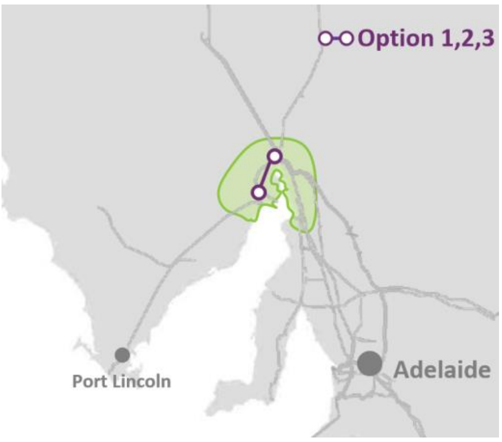
Option	Adjustment factors applied	Known and unknown risks applied
Option 1 and 2	• Delivery timetable: Long • Land use: Grazing • Project network element size: 100 - 200 km, no. of bays 11-15 for Option 1 and 6-10 for Option 2 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote • Terrain: Flat/Farmland	• Known risks: BAU • Unknown risks: Class 5

† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW.

4.4.5 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-SA Mid-North group constraints.

The capability of this zone to accommodate new generation is subject to the MN1-SA Mid-North group constraint and NSA1 northern group constraint†.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Uprate the existing 275 kV Davenport – Cultana lines with replacement current transformers (CTs), isolators, circuit breakers, line droppers, line droppers and lifting of 5 spans.	200	24	Class 5b (±50%)	Short
Option 2: • 275 kV double-circuit line, single side strung, from Davenport – Cultana.	600	166	Class 5b (±50%)	Long
Option 3: • String second 275 kV single-circuit from Davenport – Cultana. Requires option 2 already built.	600	44	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU, cost does not include line re-spanning works. • Unknown risks: Class 5
Option 2 and Option 3	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 6-10 for Option 2 and 1-5 for Option 3 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU • Unknown risks: Class 5

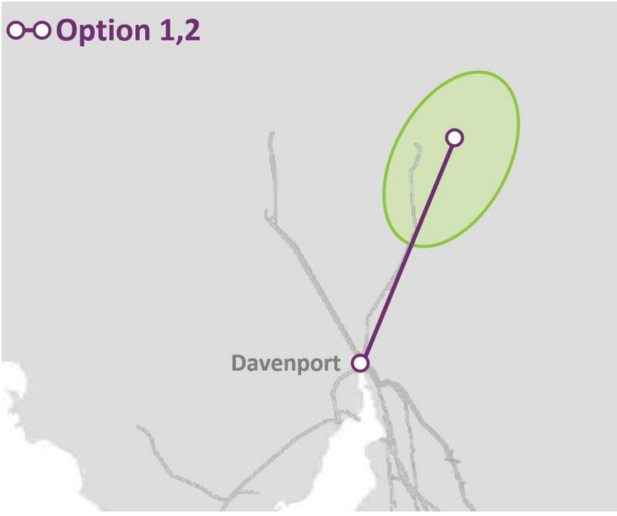
† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW or in Eyre Peninsula when S5, S8, S9 > 500.

4.4.6 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 hosting capacity within this REZ.

The capability of this zone to accommodate new generation is subject to the MN1-SA Mid-North group constraints (see Section 4.4.10). The build limit is set by this limitation at 1,000 MW†.

Augmentation options

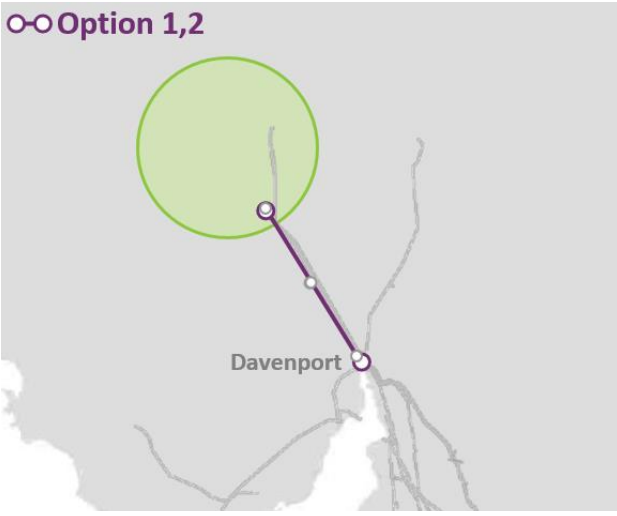
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 275 kV double-circuit line, single side strung from Davenport to new Leigh Creek substation.	500	606	Class 5b (±50%)	Long
Option 2: • String second 275 kV circuit from Davenport to new Leigh Creek substation. *Pre-requisite: Option 1*	450	192	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Options 1 and 2	• Delivery timetable: Long • Land use: Scrub (except Davenport substation which is Grazing) • Project network element size: Above 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 100% • Location (regional/distance factors): Remote • Terrain: Flat/Farmland • Indirect Cost - Stakeholder and Community Sensitive Region: Highly sensitive	• Known risks: BAU • Unknown risks: Class 5

† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW.

4.4.7 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 and privately owned 275 kV line from Davenport. ElectraNet has recently extended the 275 kV system to develop a new 275/132 kV connection point at Mount Gunson South to service OZ Minerals' new and existing mines in the area. This new 275 kV line replaces the old 132 kV Davenport to Mt Gunson South line which has been decommissioned.	
Existing network capability	
The existing network hosting capacity of this REZ is 500 MW, although the capability of this zone to accommodate new generation is subject to the MN1-SA Mid-North group constraints. The build limit is set by this limitation at 1,000 MW†.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 275 kV double-circuit single side strung from Davenport to new Roxby Downs substation.	500	424	Class 5b (±50%)	Long
Option 2: • String second 275 kV circuit line from Davenport to new Roxby Downs substation. *Pre-requisite: Option 1*	450	144	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Scrub (except Davenport substation which is Grazing) • Project network element size: 100 to 200 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU • Unknown risks: Class 5

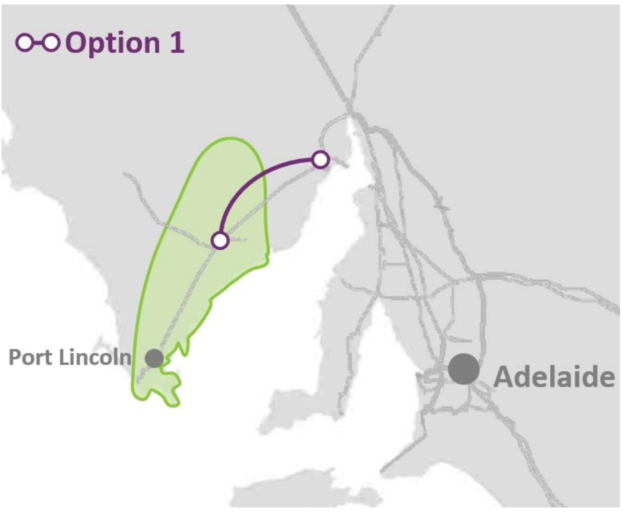
† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW.

4.4.8 Eastern Eyre Peninsula (S8)

Summary

The Eastern Eyre Peninsula REZ has moderate to good quality wind resources.

The Eyre Peninsula Link RIT–T is a committed project in which the existing Cultana–Yadnarie–Port Lincoln 132 kV single-circuit line will be replaced with a new double-circuit 132 kV line. The section between Cultana to Yadnarie will be built to operate at 275 kV, however it will be energised at 132 kV upon commissioning. This project is due to be replaced in December 2022.



Existing network capability

The existing network capacity of this REZ is 300 MW†.

The capability of this zone to accommodate new generation is subject to the MN1-SA Mid-North group constraint and NSA1 northern group constraint††.

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	Class 5a (±30%)	Medium

Adjustment factors and risk

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

† The committed Eyre Peninsula Electricity Supply Options RIT project is expected for completion by December 2022 and is assumed in the existing network hosting capacity. See https://www.aer.gov.au/system/files/AER%20-%20Eyre%20Peninsula%20Electricity%20Supply%20Options%20RIT-T%20Determination.pdf.
†† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW or in Eyre Peninsula when S5, S8, S9 > 500.

4.4.9 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 hosting capacity within this REZ.

The capability of this zone to accommodate new generation is subject to the MN1-SA Mid-North group constraint and NSA1 northern group constraint†.

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	756	Class 5b (±50%)	Long
Option 2: • 275 kV single-circuit line from Yadnarie to a new Elliston substation.	500	379	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	943	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Options 1, 2 and 3	• Delivery timetable: Long • Land use: Grazing • Project network element size: Above 200 km (Cultana-Elliston), 100-200 km (Yadnarie to Elliston), no. of bays 6-10 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU • Unknown risks: Class 5

† Additional augmentation is required in Mid-North when the combination of generation in S3, S4, S5, S6, S7, S8, S9 >1,000 MW or in Eyre Peninsula when S5, S8, S9 > 500.

4.4.10 SA Group constraints

MN1_SA

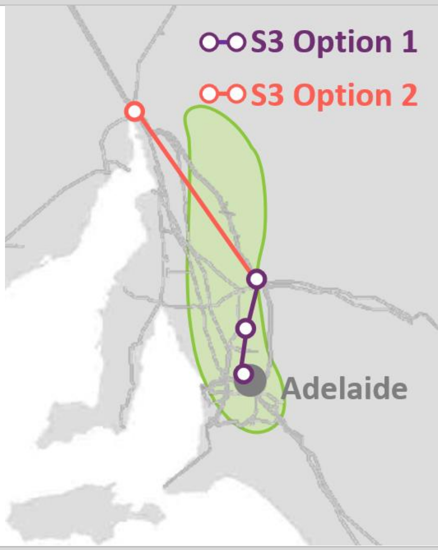
Summary

The Group Constraint MN1_SA 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 1,000 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_SA group constraint is linked to the S3 Mid-North REZ development.				
S3 Option 1: • 275 kV double-circuit lines between Robertstown, Templers West and Para.	950	340	Class 5b (±50%)	Long
S3 Option 2: • 275 kV double-circuit lines between Davenport and Robertstown.		582	Class 5b (±50%)	Long

Adjustment factors and risk

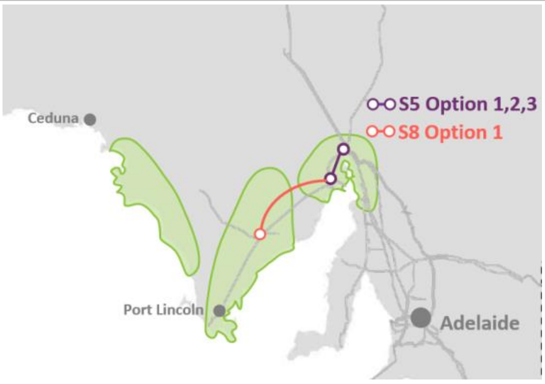
Option	• Adjustment factors applied	• Known and unknown risks applied
Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 11-15 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Regional • Terrain: Flat/farmland (except Para to Templers West which is Hilly/undulating)	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Delivery timetable: Long • Land use: Grazing • Project network element size: Above 200 km, no. of bays 1-5 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote • Terrain: Flat/farmland	• Known risks: BAU • Unknown risks: Class 5

NSA1

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 500 MW without additional network augmentation between Davenport and Cultana.

Augmentation options

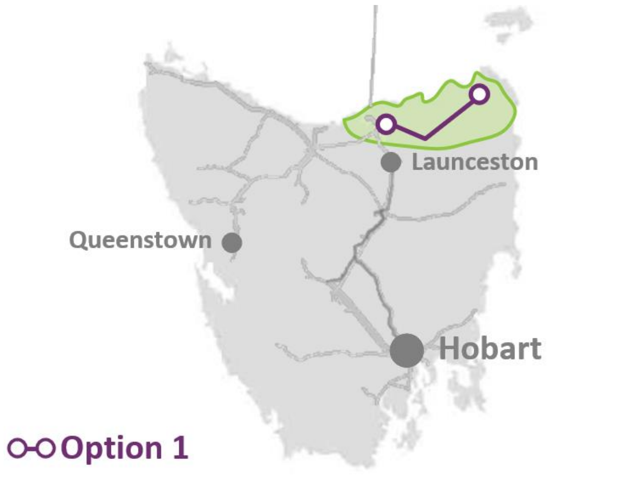
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Augmentation to alleviate the NSA1 group constraint is linked to the S5 Northern SA and S8 Eastern Eyre Peninsula REZ developments.				
S5 Option 1: • Uprate the existing 275 kV Davenport – Cultana lines with replacement CTs, isolators, circuit breakers, line droppers, line droppers and lifting of 5 spans.	200	24	Class 5b (±50%)	Short
S5 Option 2: • 275 kV double-circuit line, single side strung, from Davenport – Cultana.	600	166	Class 5b (±50%)	Long
S5 Option 3: • String second 275 kV single-circuit from Davenport – Cultana. Requires option 2 already built.	600	44	Class 5b (±50%)	Long
S8 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	Class 5a (±30%)	Medium

Adjustment factors and risk

Option	• Adjustment factors applied	• Known and unknown risks applied
S5 Option 1	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU, cost does not include line re-spanning works. • Unknown risks: Class 5
S5 Option 2 and Option 3	• Delivery timetable: Long • Land use: Grazing • Project network element size: 10-100 km, no. of bays 6-10 for Option 2 and 1-5 for Option 3) • Proportion of environmentally sensitive areas: 0% • Location (regional/distance factors): Remote	• Known risks: BAU • Unknown risks: Class 5
S8 Option 1	Cost estimate provided by ElectraNet	

4.5 Tasmania

4.5.1 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 3.10).	
Existing network capability	
Currently there is no capacity on the 110 kV network from Hadspen to Derby. There is approximately 400 MW of network capacity available at George Town.	

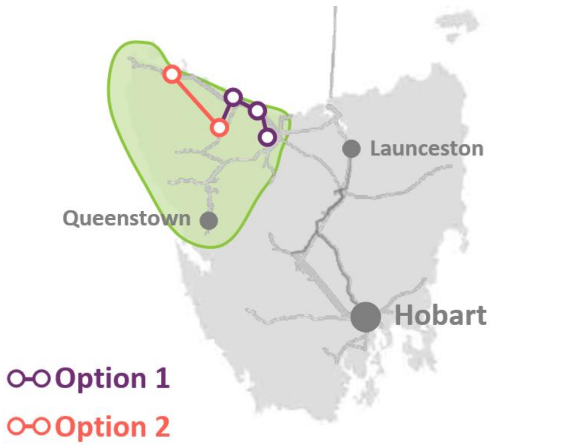
Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 80 km 220 kV double-circuit line between George Town and a new substation in north-east Tasmania.	500	230	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 1-5 • Proportion of environmentally sensitive areas: 25% • Location (regional/distance factors): Regional • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5

4.5.2 North West Tasmania (T2)

Summary	
This REZ has high quality wind resources. The North West Tasmania augmentation options are highly dependent on Marinus Link (see Section 3.10), with some REZ augmentations already included in the proposed Marinus Link AC augmentations.	
Existing network capability	
The current network hosting capacity before upgrade in North West Tasmania is approximately 340 MW. Future REZ generators are assumed to have a runback scheme in place post contingency to reduce generation output within network capacity for lines currently covered by the Network Control System Protection Scheme (NCSPS), not any new transmission lines.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)†	Cost classification	Lead time
Option 1: • Build Burnie-Heybridge-Sheffield 220 kV double-circuit transmission line. Note that Burnie-Heybridge is part of TAS-VIC Option 1 and Heybridge – Sheffield is part of TAS-VIC Option 2. • Build a double-circuit 220 kV transmission line from Hampshire to Burnie (note this is part of the Marinus Link Stage 1 augmentations).	800	115 (with Marinus Link) 259 (without Marinus Link)	Class 5a (±30%)	Long
Option 2: • Build double-circuit West Montague - Hampshire 220 kV line. *Pre-requisite: TAS-VIC Option 1*	800	298	Class 5a (±30%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Greenfield or Brownfield: Brownfield • Location (regional/distance factors): Regional • Project network element size: no. of total Bays 1-5, 10 to 100 km • Terrain: Hilly/Undulating and Mountainous • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Greenfield or Brownfield: Brownfield • Location (regional/distance factors): Regional • Project network element size: no. of total Bays 1-5, 10 to 100 km • Terrain: Hilly/Undulating and Mountainous • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5

† AEMO Transmission Cost Database estimates shown.

4.5.3 Central Highlands (T3)

Summary

This REZ has one of the best wind resources in the NEM 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.

Existing network capability

The current network hosting capacity before upgrade in the Central Highlands is approximately 480 MW across Liapootah, Waddamana and Palmerston.

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: • 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-Hadspen. • If after Marinus Link 1, build 2 x power flow controllers on the 2 x 220 kV transmission lines from Palmerston-Hadspen.	450	49 (with Marinus Link) 282 (without Marinus Link)	Class 5a (±30%)	Long
Option 2: • Build a Sheffield-Palmerston-Waddamana 220 kV line strung on one side. *Pre-requisite: Option 1 and TAS-VIC Option 2*	450	335	Class 5b (±50%)	Long
Option 3: • Build an additional Heybridge–Sheffield 220 kV single-circuit transmission line. • String other side of Sheffield-Palmerston-Waddamana 220 kV line. *Pre-requisites: Options 1 and 2 and TAS-VIC Option 2.*	550	214	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Greenfield or Brownfield: Brownfield • Location (regional/distance factors): Regional • Project network element size: no. of Bays 1-5 • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5
Option 2	• Greenfield or Brownfield: Brownfield • Location (regional/distance factors): Regional	• Known risks: BAU • Unknown risks: Class 5

	• Project network element size: 10 to 100 km, no. of Bays 1-5 • Terrain: Hilly/Undulating and Mountainous • Delivery Timetable: Long	
Option 3	• Greenfield or Brownfield: Brownfield • Location (regional/distance factors): Regional • Project network element size: 10 to 100 km, no. of Bays 1-5 • Terrain: Hilly/Undulating and Mountainous • Delivery Timetable: Long	• Known risks: BAU • Unknown risks: Class 5

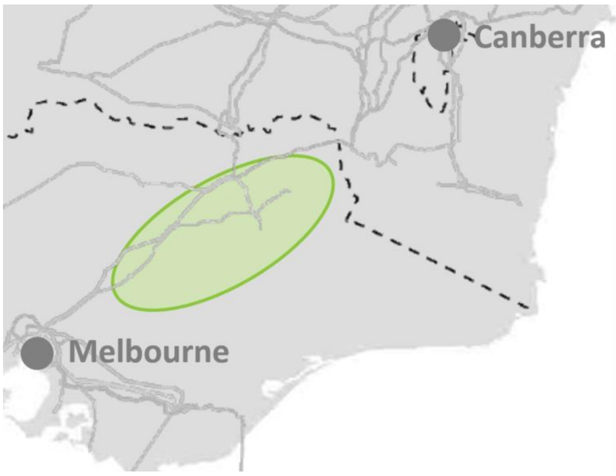
† AEMO Transmission Cost Database estimates shown.

4.6 Victoria

4.6.1 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 hosting capacity in Ovens Murray is approximately 350 MW.

Augmentation options

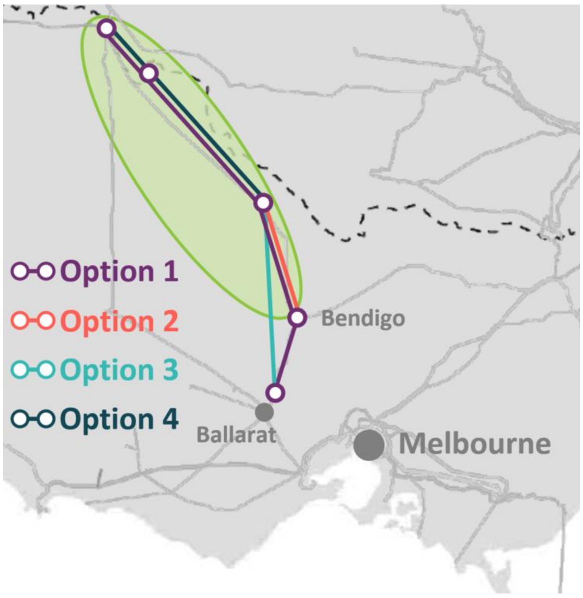
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
There are no associated augmentations with this REZ				

4.6.2 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 either Kerang or Shepparton. The development of VNI West via Kerang would significantly increase the ability for renewable generation to connect in this zone. Project EnergyConnect (see Section 1.1) will facilitate a small improvement in capacity within Murray River REZ.



Existing network capability

No additional capacity to connect new generation.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New double-circuit 220 kV line between Red Cliffs – Wemen – Kerang – Bendigo – north of Ballarat. • Establish new substations close to Redcliff, Kerang and Bendigo. • New 500/220 kV 1,000 MVA transformer north of Ballarat.	1,200	1,300	Class 5b (±50%)	Long
Option 2: • New double-circuit 500 kV line between Kerang – Bendigo (including 2 new 500/220 kV transformers at Kerang). • Establish new substations close to Kerang and Bendigo. • Turn the 500 kV line from north of Ballarat to Shepparton into Bendigo (including new 500 kV substation near Bendigo). *Pre-requisite: VNI West (Shepparton)*	1,300	931	Class 5b (±50%)	Long
Option 3: • New double-circuit 500 kV line between north of Ballarat – Kerang (including 2 new 500/220 kV transformers at Kerang). • Establish new substation close to Kerang.	1,250	1,165	Class 5b (±50%)	Long
Option 4: • New 220 kV double-circuit line between Red Cliffs – Wemen – Kerang. • Establish new substations close to Redcliff and Kerang. *Pre-requisite: VNI West (Kerang)*	800	665	Class 5b (±50%)	Long

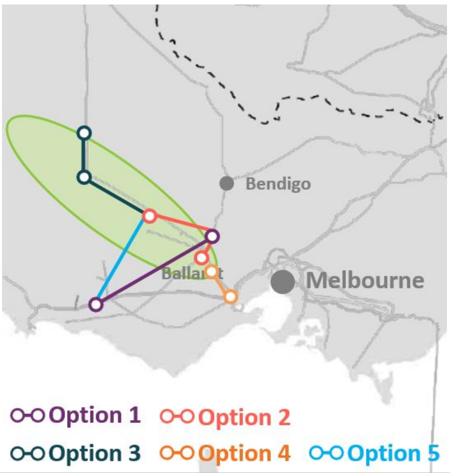
Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 2	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 3	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 4	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

4.6.3 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 gigawatt (GW), all of which is from wind generation. The current network is constrained and cannot support any further connection of renewable generation without transmission augmentation.

The Western Victoria Transmission Network Project is an anticipated project (see Section 1.1), with the preferred option to expand generation within this zone.



Existing network capability

Approximately 450 MW of new generation can be connected after the completion of the Western Victoria Transmission Network Project.

Augmentation options

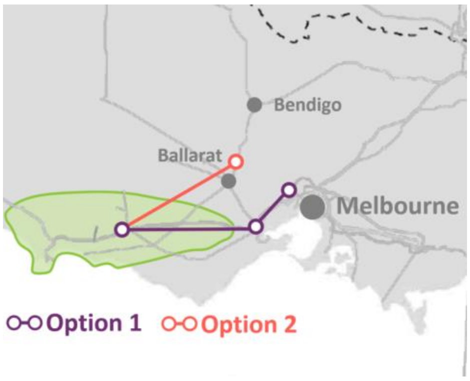
Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • Build a new single-circuit 500 kV line between Mortlake - new 500 kV substation north of Ballarat.	1,200	1,072	Class 5b (±50%)	Long
Option 2: • Build a new double-circuit line between north of Ballarat - Bulgana (with one circuit turning into Ararat and Crowlands). • Replace existing single-circuit 220 kV line from north of Ballarat to Ballarat with a double-circuit line. • New 1,000 MVA 500/220 kV transformer north of Ballarat. • Series reactor on Crowlands-Ararat-Bulgana circuit.	800	623	Class 5b (±50%)	Long
Option 3: • New 220 kV double-circuit line between Murra Warra - Bulgana via Horsham. • Establish new substation close to Horsham. *Pre-requisite: V3 Option 2 or Option 3.*	1,000	430	Class 5b (±50%)	Long
Option 4: • New 220 kV single-circuit line between Elaine - Moorabool.	600	152	Class 5b (±50%)	Long
Option 5: • New 500 kV double-circuit line between Bulgana - Mortlake.	1,000	772	Class 5b (±50%)	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

Option 2	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 3	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 4	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 5	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

4.6.4 South West Victoria (V4)

Summary	
The South West Victoria REZ has moderate to good quality wind resource 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.	
Existing network capability	
Currently the 220 kV network is already congested. The current total network hosting capacity is approximately 2,500 MW for this REZ.	

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 500 kV single-circuit line between Mortlake – Moorabool – Sydenham.	1,500	930	Class 5b (±50%)	Long
Option 2: • New 500 kV single-circuit line between Mortlake - north of Ballarat. • Turn Tarrone – Haunted Gully line into Mortlake substation.	1,200	851	Class 5b (±50%)	Long

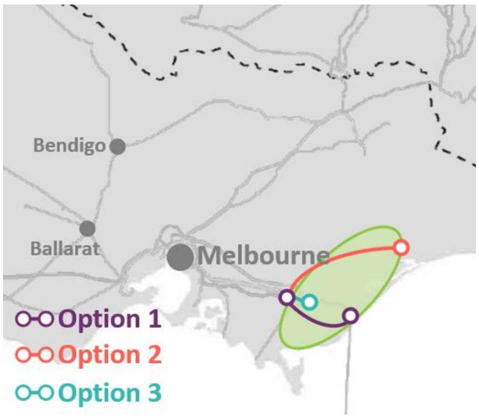
Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 2	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

4.6.5 Gippsland (V5)

Summary

There is currently significant wind generation interest in this area, including a large offshore wind farm of 2,000 MW.



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 2,000 MW of new VRE can be accommodated prior to network augmentations. Options shown extend the network further to allow for easier connection of generation.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 500 kV double-circuit line between Hazelwood - vicinity of Basslink transition station. • Two 500/220 kV transformers • 250 MVAr dynamic reactive compensation	2,000	588	Class 5b (±50%)	Long
Option 2: • New 220 kV double-circuit line between Hazelwood - Bairnsdale.	800	458	Class 5b (±50%)	Long
Option 2: • New 500 kV double-circuit line between Hazelwood - Loy Yang • 250 MVAr dynamic reactive compensation	2,000	442	Class 5b (±50%)	Long

Adjustment factors and risk

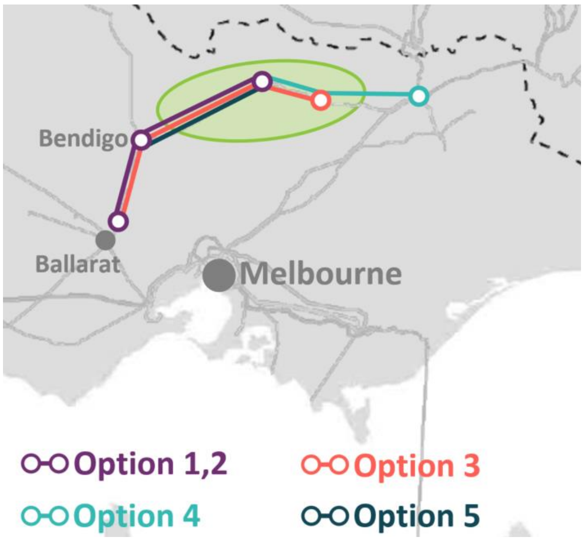
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 2	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 3	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

4.6.6 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, the solar generation applications exceed 200 MW whilst the enquires within this zone exceeds 2.5 GW.

The potential VNI West project could increase transfer capability between Victoria and New South Wales via either Kerang or Shepparton. The development of VNI West via Shepparton would significantly increase the ability for renewable generation to connect in this zone.



Existing network capability

The current total network hosting capacity in Central North Victoria is approximately 800 MW.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • New 500 kV substation near Shepparton (including two 500/220 kV transformers). • New 220 kV double-circuit line between north of Ballarat - Bendigo - Shepparton.	1,700	1,364	Class 5b (±50%)	Long
Option 2: • New 220 kV double-circuit line between north of Ballarat - Bendigo - Shepparton. • Establish new substations close to Bendigo and Shepparton	900	725	Class 5b (±50%)	Long
Option 3: • New 220 kV double-circuit line between north of Ballarat – Bendigo - Shepparton - Glenrowan. • Establish new substations close to Bendigo and Shepparton	850	980	Class 5b (±50%)	Long
Option 4: • Replace existing 220 kV single-circuit line between Shepparton to Dederang via Glenrowan with a double-circuit line.	600	509	Class 5b (±50%)	Long
Option 5: • New 220 kV double-circuit line between Bendigo to Shepparton. • Establish new substation close to Bendigo.	700	476	Class 5b (±50%)	Long

Adjustment factors and risk		
Option	**Adjustment factors applied**	**Known and unknown risks applied**
Option 1	• Location for transmission line 'regional' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 2	• Location for transmission line 'regional' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 3	• Location for transmission line 'regional' • Land use 'grazing' • Total circuit length 'above 200 km' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 4	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5
Option 5	• Location for transmission line 'regional' • Land use 'grazing' • Delivery timetable 'long' • Proportion of environmentally sensitive areas '50%'	• Known risks: High • Unknown risks: Class 5

4.7 Offshore wind zones

The ISP considers options for offshore wind development via offshore wind zones (OWZs). The following table outlines the OWZs considered in the ISP, with locations shown in Figure 7 (in Section 4.1). More information on OWZs is available in the 2021 IASR[34].

Table 10 Offshore wind zones

ID	OWZ Name	Region	Connection Point
O1	Hunter Coast	NSW	Eraring 500 kV
O2	Illawarra Coast	NSW	Dapto 330 kV
O3	Gippsland Coast	VIC	Loy Yang 500 kV
O4	North West Tasmanian Coast	TAS	Burnie 220 kV

[34] AEMO, 2021 IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

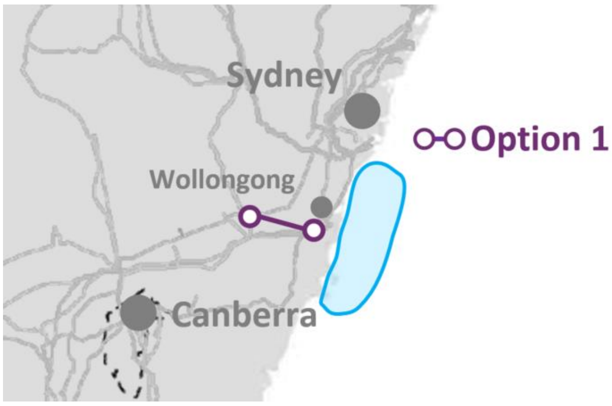
Options to expand network access to OWZs are included as follows:

- **Hunter Coast** – Due to the proximity to major load centres and local network capacity, no network augmentations are necessary to accommodate offshore wind on the Hunter Coast.
- **Illawarra Coast** – One network augmentation option is outlined in Section 4.7.1.
- **Gippsland Coast** – Network augmentation options outlined for the Gippsland REZ are applicable for connecting offshore wind in the Gippsland Coast (see Section 4.6.5).
- **North West Tasmanian Cost** – Network augmentation options outlined for the North West Tasmania REZ are applicable for connecting offshore wind in the North West Tasmanian Coast (see Section 4.5.2).

4.7.1 Illawarra Coast

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.



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 hosting capacity is approximately 1,000 MW.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	Cost classification	Lead time
Option 1: • 80 km 500 kV double-circuit line from Dapto – Bannaby. • Substation works and two 500/330 kV 1,500 MVA transformers at Dapto	2,000	470	Class 5b (±50%)	Long

Adjustment factors and risk

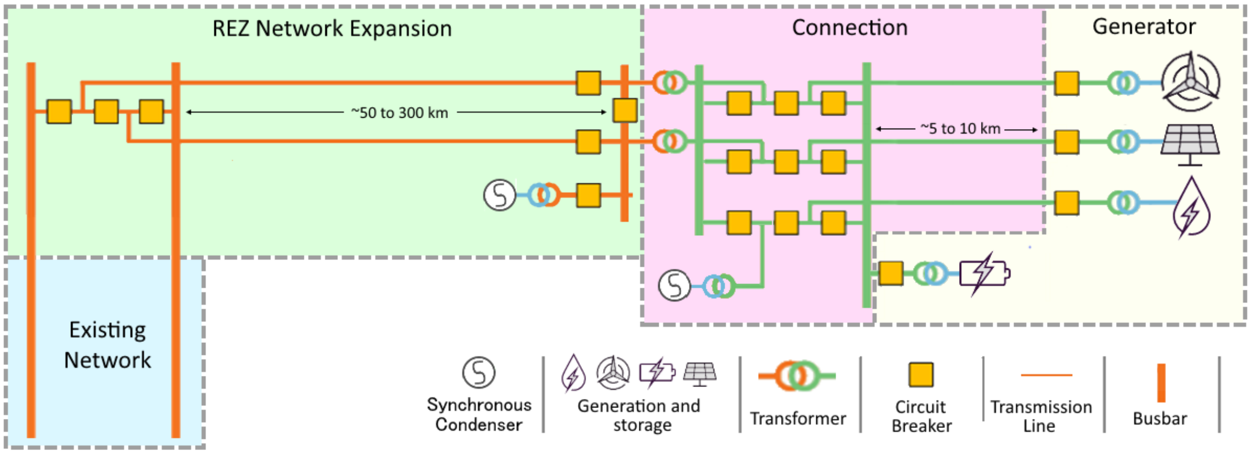
Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Location for transmission line 'regional' • Total circuit length '10-100 km' • Delivery timetable 'long'	• Known risks: BAU • Unknown risks: Class 5

5. Generator connection costs

This chapter outlines the costs associated with the connection new generators to the network. Generator connection costs describe the network elements required to physically connect to the wider network as well as any system strength remediation costs where applicable.

Figure 8 illustrates how connection costs are defined in relation to the REZ network expansion costs.

Figure 8 Connection cost representation



5.1 Connection costs

Connection costs are added to generator costs to account for the transmission infrastructure required to connect a generator within a REZ to the REZ network. The connection costs vary depending on the proximity to transmission assets and the voltage of the network.

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 VRE.

Table 11 describes the parameters of the connection assets used for solar, wind, and solar thermal generation connecting in each REZ, and Table 12 describes parameters for other generation technologies which are close to the network. Table 13 describes parameters for batteries which require no feeder.

Table 11 Connection costs for solar, wind, and solar thermal 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	37	123.33
North Queensland Clean Energy Hub	QLD	275	300	10	47	156.67
North Queensland	QLD	275	300	5	37	123.33
Isaac	QLD	275	300	5	37	123.33
Barcaldine	QLD	275	300	10	47	156.67
Fitzroy	QLD	275	300	5	37	123.33
Wide Bay	QLD	275	300	5	37	123.33.
Darling Downs	QLD	275	300	5	37	123.33
Banana	QLD	275	300	5	37	123.33
North West New South Wales	NSW	330	400	10	53	132.50
New England	NSW	330	400	10	53	132.50
Central West New South Wales	NSW	330	400	10	53	132.50
Cooma-Monaro	NSW	330	400	5	41	102.50
Wagga Wagga	NSW	330	400	10	53	132.50
Tumut	NSW	330	400	5	41	102.50
South West New South Wales	NSW	330	400	10	53	132.50
Broken Hill	NSW	220	250	10	44	176.00
Murray River	VIC	220	250	5	34	136.00
Western Victoria	VIC	220	250	5	34	136.00
South West Victoria	VIC	500	600	10	64	106.67
Ovens Murray	VIC	220	250	5	34	136.00
Gippsland	VIC	220	250	10	44	176.00
Central North Victoria	VIC	220	250	10	44	176.00
South-East SA	SA	275	300	10	47	156.67
Riverland	SA	275	300	10	47	156.67
Mid-North SA	SA	275	300	5	37	123.33
Yorke Peninsula	SA	275	300	5	37	123.33

REZ names	Region	REZ network voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($ million)	Cost ($/kW)
Northern SA	SA	275	300	5	37	123.33
Leigh Creek	SA	275	300	10	47	156.67
Roxby Downs	SA	275	300	10	47	156.67
Eastern Eyre Peninsula	SA	275	300	10	47	156.57
Western Eyre Peninsula	SA	275	300	10	47	156.67
North-West Tasmania	TAS	220	150	5	34	226.67
Central Highlands	TAS	220	150	5	34	226.67
North-East Tasmania	TAS	220	150	5	34	226.67
Adjustment factors and risk						
All options	• Location (regional/distance factors): Regional • Project network element size: no. of total Bays 1-5			• Known risks: BAU • Unknown risks: Class 5		

Table 12 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	45	75.00
330	400	1	32	80.00
275	300	1	31	103.33
220	250	1	27	108.00
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	

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

Table 13 Connection costs for batteries

Connection voltage (kV)	Connection capacity (MVA)	Total cost ($ million)	Cost ($/kW)
500	600	41	68.33
330	400	29	72.50
275	300	29	96.67
220	250	25	100.00
Adjustment factors and risk			
All options	• Project network element size: no. of total Bays 1-5	• Known risks: BAU • Unknown risks: Class 5	

5.2 System strength remediation costs

System strength remediation is a complex requirement that is dependent on synchronous generation dispatch, network upgrades, and the scale of local inverter-based resources (IBR). As such, any remediation requirements not already built into network upgrade costs are post-processed. Section 4.2.4 of AEMO's *ISP Methodology*[35] provides an overview of the fault level calculation methods used to derive system strength mitigation requirements.

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 14 System strength remediation options

Description	Expected cost ($ million)	Cost classification	Lead time
80 MVA synchronous condenser	56	Class 5b (±50%)	Medium
125 MVA synchronous condenser	74	Class 5b (±50%)	Medium
250 MVA synchronous condenser	140	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 5	

Based on 2020 ISP studies, system strength remediation for the Step Change Scenario (see ISP Appendix 5[36]) calculated a need for 15 × 125 megavolt-amperes (MVA) synchronous condensers, and 17 × 250 MVA synchronous condensers, to cater for 33 gigawatts (GW) of new renewables across the NEM. Using the updated Transmission Cost Database, this translates to an additional $0.106 million/megawatt (MW) if included in REZ expansion costs, or $106/kilowatt (kW) if included in generator connection costs. The process to account for system strength costs is outlined in the *ISP Methodology*[37].

The breakdown of which REZs have system strength remediation costs allocated to REZ expansion cost or generator connection costs is shown in the 2021 IASR[38].

[35] AEMO. *Consultation on the ISP Methodology*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

[36] At https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf.

[37] AEMO. *Consultation on the ISP Methodology*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

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

A1. Cost classification checklist

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

	Class 5		Class 4	Class 3	Class 2/1
Class sub-category	'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

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

	Class 5		Class 4	Class 3	Class 2/1
Class sub-category	'b'	'a'			
Which option best describes the current level of engagement with landowners?	None	None	None	Community Level	Landowner Level
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

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