Transgrid

People. Power. Possibilities.

Increasing capacity for generation in the Wagga North area

RIT-T Project Assessment Draft Report

Region: Southern NSW

Date of issue: 23 December 2025

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for increasing capacity for renewable generation in the Wagga North area. Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process following the Project Specification Consultation Report (PSCR) we published on 19 December 2024.

The Wagga North area has seen significant growth in renewable generation connections to the transmission network, as part of the wider energy market transition. Currently, approximately 409 MW of renewable generation is already in service in this area.

Lines 9R5, 9R6 and 991 play a central role in transmitting the electricity from these renewable generators via our Wagga North 132/66 kV and Wagga 330/132 kV substations. Our analysis shows that the load requirements on Lines 9R5 and 9R6 exceed their thermal rating under system normal network conditions if the current in-service renewable generators in the Wagga North area are dispatched to their maximum capacities. Lines 9R6 and 9R5 have consistently appeared as top 10 binding constraints in AEMO's monthly constraint reports, with renewable generation being constrained to ensure reliable operation of the lines.

We have identified an opportunity to upgrade the 132 kV Lines 9R6 and 9R5 supplying Wagga North 132/66 kV substation to alleviate potential thermal constraints due to recent renewable generation developments in the Wagga North area. In all credible scenarios there is expected to be significant economic benefits to the National Electricity Market (NEM) to strengthen the transmission network to relieve this constraint and realise net market benefits by avoiding curtailment of low-cost renewable generation in the Wagga North area.

Identified need: provide net benefits to the market by increasing capacity for renewable generation in the Wagga North area

The identified need for this RIT-T is to increase overall net market benefits in the NEM through increasing capacity and relieving existing constraints on renewable generation in the Wagga North area. This will enable greater output from renewable generation in this region of the NEM.

We have classified this RIT-T as a 'markets benefits' driven RIT-T, relieving existing transmission constraints and delivering market benefits primarily through lower capital costs, by reducing (or deferring) the need for new investment in generation plants.:

The PADR analysis has benefited from stakeholder consultation

We received seven submissions in response to the PSCR which can be grouped into three categories:

- existing renewable generators in the Wagga North area;
- a developer of a proposed battery energy storage systems (BESS) in the Wagga North area; and
- a gentailer operating in the NEM.

All of the submissions agreed with the identified need for this RIT-T. Five of the submissions indicated a preference for Option 2 presented in the PSCR. This option involved increasing Lines 9R5 and 9R6 normal rating to a minimum of 223 MVA by restringing the lines with a higher-temperature conductor operating at

180°C. Two of the submissions indicated that some of the options identified in the PSCR would address the identified need in the short term, but more significant investment in network augmentation or BESS may help to address the identified need in the long term if more renewable generation connects to the Wagga North region.

We have summarised and responded to these submissions in this PADR. These submissions have played a key role in developing the PADR and we thank all parties for their time and effort to-date. Submissions approved for publication are available on our website.

Key developments since the PSCR have been reflected in the PADR

Since releasing the PSCR, Transgrid has reviewed the rating of the busbars at the 132/66 kV Wagga substation. The older busbar, constructed from galvanised steel pipe, differs from Transgrid's current minimum standard aluminium tube design. This legacy busbar has a minimum summer day rating of 581 Amps, which is broadly equivalent to the rating of smaller 132 kV line conductors.

At present, loading on the busbar at Wagga substation is contained within its operational limits because the existing feeder lines restrict capacity to a level below that of the busbar. However, this RIT-T is assessing options to expand the capacity of feeder lines to Wagga substation. All of the network options considered in the PSCR would increase feeder capacity to levels exceeding the rating of the busbar. Transgrid has identified that, under all of these options (Options 1-4 in this PADR), there will be times when load and/or generation must be constrained to ensure that the loading on the busbar does not exceed its designated rating. In effect, without upgrading the busbar at Wagga substation, market participants would not be able to utilise the full capacity of the new feeder lines. This means renewable generation in the Wagga North area would continue to face constraints after the line upgrade, but now due to the busbar rather than the feeders.

Transgrid considers that increasing the capacity of the busbar at Wagga substation will help to address the identified need for this RIT-T as it contributes to relieving constraints on renewable generation in the Wagga North area. In view of this, we have updated each of the PSCR options (Options 1-4 in this PADR) to include the cost of uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design). We consider that the upgrade to the feeder lines and the busbar at Wagga substation form an integrated solution to meet the identified need, in line with the AER's RIT-T application guidelines.

The estimated cost of the upgrading the busbar at Wagga substation is $6.55 million (FY2024/25). This cost has been incorporated into all options identified in the PSCR to ensure feeders are not constrained by the existing busbar rating. Since this upgrade is necessary for Options 1-4, it has not changed the ranking of these options or the identification of the preferred option.

In addition, following the feedback provided by stakeholders, we have included an additional network option which involves the development of a 120 MW / 480 MWh battery energy storage system (BESS) in the Wagga North area. For the purposes of this PADR, we have assumed that a BESS could be developed by Transgrid. As per other network options, our analysis estimates the development cost of a BESS and the market benefits associated with the BESS being added to the network.

Five credible network options have been identified

We have identified five credible network options that meet the identified need from a technical, commercial, and project delivery perspective.[1] These options are summarised in Table E-1 below.

Table E-1: Option summary ($m 2024/25)

Option	Description	Estimated capital cost[2]	Estimated capital cost of 132 kV busbar upgrade	Estimated total capital cost	Expected delivery time[3]
Option 1	Restring Lines 9R5 and 9R6 with "Mango" ACSR/GZ[4] conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	14.3 (+/- 25%)	6.55 (+/- 25%)	20.82 (+/- 25%)	2027/28
Option 2	Restring Lines 9R5 and 9R6 with a high- temperature low-sag conductor and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	12.5 (+/- 25%)	6.55 (+/- 25%)	19.09 (+/- 25%)	2027/28
Option 3	Construct a new double circuit 132 kV transmission line from Wagga 330 kV substation to near Wagga North 132/66 kV substation with Line 991 re-routed, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	49.9 (+/- 25%)	6.55 (+/- 25%)	56.47 (+/- 25%)	2030/31
Option 4	Construct a new single circuit 132kV transmission line between Wagga North 132/66 kV substation and Wagga 330 kV substation, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	38.6 (+/- 25%)	6.55 (+/- 25%)	45.11 (+/- 25%)	2029/30
Option 5[5]	Develop a 120 MW / 480 MWh BESS in Wagga North area.	215.0 (+/- 25%)	N/A	215.00 (+/- 25%)	2027/28

Market benefits have been assessed under three scenarios

The options considered will affect dispatch outcomes in the wholesale market, relative to the 'do nothing' base case. In particular, the additional transmission capacity is expected to provide for more efficient outcomes in the wholesale market, by increasing the output of low-cost renewable generation in the Wagga area and displacing higher cost conventional generation elsewhere. However, uncertainty exists in terms of

1 As per clause 5.15.2(a) of the NER.
2 For Options 1-4 this column presents the cost of the line upgrade component
3 Delivery timeframes will be reviewed as part of the PACR and may change
4 Aluminium conductor steel-reinforced cable.
5 Cost estimates for Option 5 are drawn from AEMO data from the latest Input, Assumptions and Scenarios Report (IASR)

estimating future inputs and variables (termed future 'states of the world'). In order to estimate the market benefits, Transgrid undertook wholesale market modelling for the proposed options under the three ISP scenarios by applying the inputs used in AEMO's 2024 ISP Detailed Long Term (DLT) model.

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option. The credible options have been assessed under three scenarios as part of this PADR, which reflect the scenarios from AEMO's 2024 Integrated System Plan (ISP).

At the time of preparing this report, AEMO's updated 2026 ISP Detailed Long-Term (DLT) model has not yet been released. Once the 2026 ISP model becomes available, the market modelling will be revisited and updated as part of the PACR stage to ensure alignment with the latest assumptions and scenarios.

The table below summarises the variables that influence the net benefits of the options under each of the scenarios considered in this PADR. The three scenarios have been weighted based on the ISP weights.

Table E-2: Summary of scenarios

Variable	Green Energy Exports	Step Change	Progressive Change
Capital costs	Base estimate	Base estimate	Base estimate
Demand	POE50	POE50	POE10
Renewable generation in the area	In-service and committed generators (as outlined in section 2.2)	In-service and committed generators (as outlined in section 2.2)	In-service and committed generators (as outlined in section 2.2)
Wholesale market benefits estimated	Transgrid estimate based on the 'green energy exports' 2024 ISP scenario	Transgrid estimate based on the 'step change' 2024 ISP scenario	Transgrid estimate based on the 'progressive change' 2024 ISP scenario
Discount rate	7.0%	7.0%	7.0%
Scenario weighting[6]	15.0%	43.0%	42.0%

Option 2 is the preferred option

Option 2 produces the highest net benefits under each of the three ISP scenarios. Option 1 also achieves positive net economic benefits at a slightly higher capital cost. However, given gross market benefits from Option 2 are materially higher, we consider Option 2 as the preferred option.

Options 3, 4 and 5 deliver negative net economic benefits. Both Options 3 and 4 deliver lower gross market benefits compared to the preferred option, while also being considerably more costly. Option 5 delivers higher gross market benefits compared to the preferred option, but these benefits are outweighed by the substantially higher capital cost of the BESS.

We have also considered integrated solutions combining network (re-string) and non-network (BESS) projects. However, our analysis indicates that Option 5 (a standalone BESS) is not net beneficial (refer to

[6] Consistent with the scenario likelihoods outlined in AEMO's 2024 ISP.

Section 7.3). It follows that the BESS would not provide additional net benefit when deployed as an increment to a network option that addresses the constraint. As such, an integrated solution combining network and non-network projects were not progressed further.

Table E-3: NPV of net economic benefits relative to the base case – Weighted scenario ($m 2024/25)

Option	Weighted scenario
Option 1	10.7
Option 2	21.7
Option 3	-19.1
Option 4	-11.1
Option 5	-120.1

Submissions and next steps

We welcome written submissions on materials contained in this PADR. Submissions are due on 7 February 2026[7] and should be emailed to our Regulation team via regulatory.consultation@Transgrid.com.au.[8] In the subject field, please reference 'Wagga North Capacity Increase PADR.'

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the publication of the PACR, which is anticipated to be published by mid-2026.

7 PADR consultation is for six weeks and additional days are added to cover public holidays.

8 Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

Contents

1. Introduction

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We have identified an opportunity to upgrade the 132 kV Lines 9R6 and 9R5 supplying Wagga North 132/66 kV substation to alleviate potential thermal constraints due to recent renewable generation developments in the Wagga North area. In all credible scenarios there is expected to be significant economic benefits to the National Electricity Market (NEM) to strengthen the transmission network to relieve this constraint and realise net market benefits by avoiding curtailment of low-cost renewable generation in the Wagga North area.

1.1 Purpose of this report

The purpose of this PADR[9] is to:

- confirm the identified need for the investment, and describe the assumptions underlying this need, including any changes to these assumptions since the PSCR;
- summarise the consultation undertaken since the PSCR and highlight how it has been reflected in the RIT-T analysis;
- describe the options being assessed under this RIT-T, including how these have been shaped as part of the PSCR consultation and the additional options proposed in submissions.
- identify and confirm the market benefits expected from the various credible options;
- summarise our approach to modelling the net market benefits for each credible option assessed, and present the results of this analysis;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the preferred option at this stage of the RIT-T, i.e., the option that is expected to maximise net market benefits.

[9] See Appendix A for the National Electricity Rules requirements.

Overall, this report provides transparency into the planning considerations for investment options to relieve transmission constraints in the Wagga North area, and the associated market benefits. A key purpose of this PADR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

1.2 Submissions and next steps

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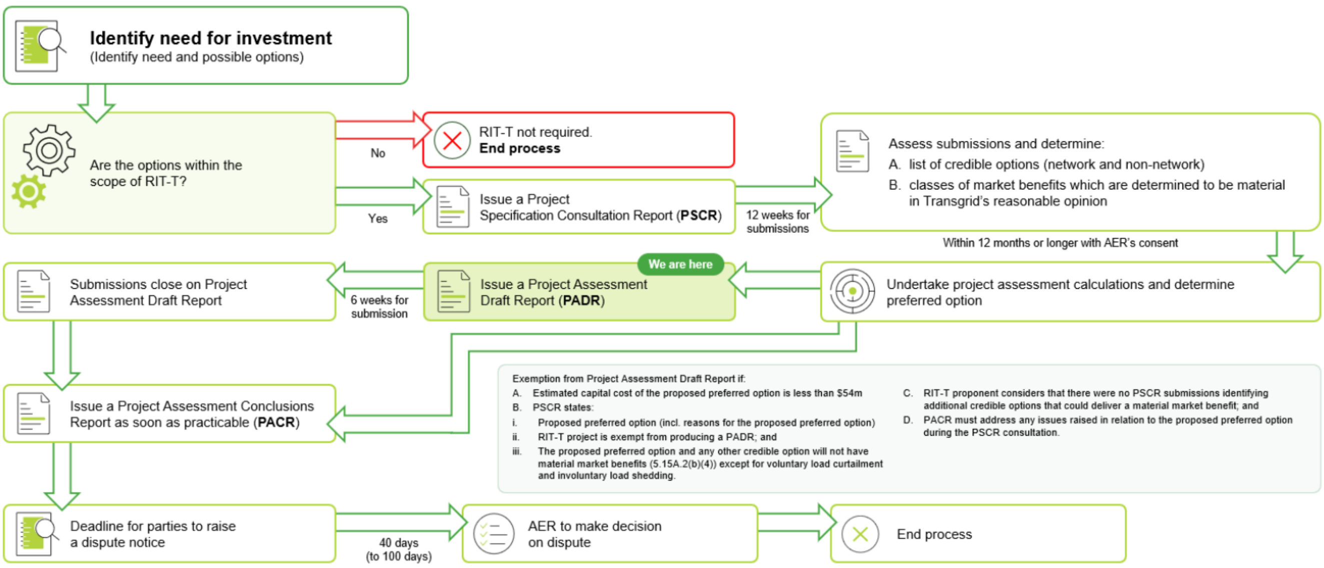
The next formal stage of this RIT-T is the publication of the PACR, which is anticipated to be published in by mid-2026.

Figure 1-1: This PADR is the second stage of the RIT-T process



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2. The identified need

This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It sets out background information related to the transmission network in the Wagga area.

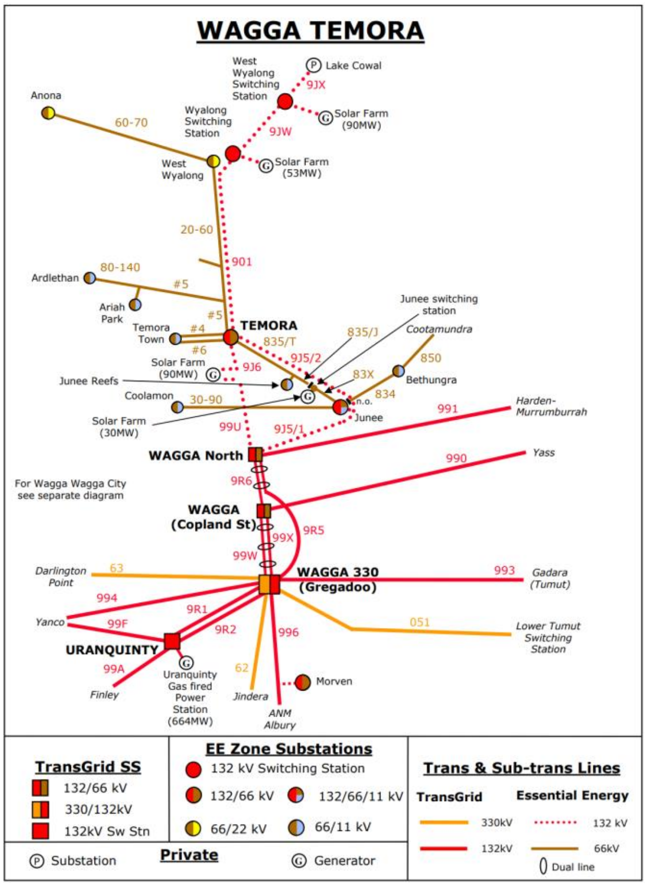
2.1 Background to the identified need

Transgrid's Wagga North 132/66 kV substation is in Southern NSW in an area with significant new investment in renewable generation. Transgrid provides bulk supply from Wagga North substation.

The Wagga North substation is supplied by 132 kV Lines 9R5, 9R6 and 991. These lines are strung with ACSR Panther conductors at a design operating temperature of 85°C. These lines have normal and emergency ratings of 125 MVA and 137 MVA respectively. Lines 9R5 and 9R6 interconnect Wagga North 132/66 kV and Wagga 330/132 kV substations, while Line 991 connects to Yass 330/132 kV substation via Murrumburrah. Lines 9R5 and 9R6 are approximately 12km and 7.8km long, respectively.

A map showing the location of the Wagga North area and Essential Energy's network in the Temora region is set out below in Figure 2-1.

Figure 2-1: Transgrid and Essential Energy network in Wagga/Temora area[12]



2.2 Description of the identified need

The thermal constraints imposed due to the rating of the 132 kV Lines 9R5, 9R6 and 991 are constraining the output of renewable generation in the Wagga area. At times of high generation output, thermal overloading of these lines can occur. This has resulted in the Australian Energy Market Operator (AEMO) introducing operational constraints in the NEM Dispatch Engine (NEMDE) to limit power flows to manage the risk of thermal overload. AEMO's monthly constraint reports[13] have consistently identified lines in the Wagga North area as a top 10 constraint on the NEM since September 2023.

Table 2-1 below summarises the most recent AEMO monthly constraint reports relevant to Wagga North 9R5, 9R6 and 991 lines. AEMO additionally provides data on the total hours each constraint was binding during previous calendar years. The 9R5 and 9R6 lines were binding for 605.3 and 568.9 hours in 2023 and 2024, respectively.[14]

[12] Essential Energy, 2024, Distribution Annual Planning Report Dec 2024

[13] AEMO, various dates, *Monthly Constraint Reports*. Accessed from: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams

[14] Where the total hours is equal to the sum of the annual constraint on equation N>NIL_9R5_9R6 and N>NIL_9R6_9R5.

Table 2-1: Summary of AEMO monthly constraint reports

Year	Month	Top 10 position	Constraint Equation ID	#DIs (Hours)	Limit Type
2023	September	10th	N>NIL_9R6_991	1356 (113.0)	Thermal
2023	October	9th	N>NIL_9R6_9R5	1156 (96.3)	Thermal
2023	November	7th	N>NIL_9R6_991	1519 (126.6)	Thermal
2023	December	6th	N>NIL_9R6_991	1736 (144.7)	Thermal
2024	January	7th	N>NIL_9R6_991	2084 (173.7)	Thermal
2024	February	7th	N>NIL_9R6_991	2045 (170.4)	Thermal
2024	March	4th	N>NIL_9R6_991	1766 (147.2)	Thermal
2024	April	5th 9th	N>NIL_9R6_9R5 N>NIL_9R6_991	1100 (91.7) 732 (61.0)	Thermal Thermal
2024	May	5th	N>NIL_9R6_9R5	532 (44.3)	Thermal
2024	October	6th	N>NIL>9R6_991	1507 (125.6)	Thermal
2024	November	5th	N>NIL>9R6_991	1433 (119.4)	Thermal
2024	December	4th	N>NIL>9R6_991	2113 (176.1)	Thermal
2025	January	7th	N>NIL>9R6_991	1709 (142.4)	Thermal
2025	February	4th	N>NIL>9R6_991	1919 (159.9)	Thermal
2025	March	3rd	N>NIL>9R6_991	1856 (154.7)	Thermal
2025	April	8th	N>NIL>9R6_991	1161 (96.8)	Thermal

The identified need for this RIT-T is to increase consumer and producer surplus in the NEM through relieving network constraints on the supply of renewable generation in the Wagga North area. This will enable a greater amount of renewable generation produced in the Wagga area to be supplied to customers in the NEM.

Within the context of the RIT-T assessment, greater supply of renewable generation is expected to deliver market benefits primarily through lower capital costs, by reducing (or deferring) the need for new investment in generation plants to meet growing electricity demand in the future.

2.3 Assumptions underpinning the identified need

This section sets out the key assumptions underpinning the identified need.

2.3.1 Renewable generation in the Wagga North area is growing

There have been recent developments of renewable generation in the Wagga North area. Currently, Essential Energy and Transgrid have approximately 409 MW of in-service generation connected to north of Wagga North substation. Transgrid is aware of two additional BESS that are proposed to be developed in the area with a combined capacity of 120MW.

Table 2-2:3 Current and Planned generation in the Wagga North region

Renewable Source	Connection point	Maximum Capacity (MW)[15]	Status
Wagga North Solar Farm	Wagga North	46	In service
Junee Solar Farm	Junee Switching Station	30	In service
Sebastopol Solar Farm	Sebastopol	90	In service
West Wyalong Solar Farm	West Wyalong Switching Station	90	In service
Wyalong Solar Farm	Wyalong Switching Station	53	In service
Bomen Solar Farm	Bomen	100	In service
Total MW (in-service)		**409**	

The total amount of in-service generation has resulted in thermal loading limitations on the 132kV lines connected to the Wagga North substation.

2.3.2 Proposed BESS in the region have not reached anticipatory status

As at July 2025, information published by AEMO indicates that there are three BESS proposed to be developed in the Wagga North region. These are:

- a 120 MW BESS by AE BESS 2 Pty Ltd;
- a 105 MW BESS by ZEN Energy Future Pty Ltd; and
- a 120 MW BESS by IB Vogt.

The status of these projects are listed by AEMO as 'proposed.' Transgrid has not received any additional information to suggest that the status of the projects has changed to either 'committed' or 'anticipated.' Consistent with the RIT-T Guidelines, we have not included these projects in our modelling of the base case or each of the investment cases for the purposes of identifying the preferred option.

2.3.3 Thermal capacity of Line 9R5 and Line 9R6 is insufficient to meet increasing generation requirements

Our analysis shows that the load requirements on Lines 9R5 and 9R6 would exceed their thermal rating under system normal network conditions if the current in-service renewable generators in the Wagga area are dispatched to their maximum capacities.

The particular lines that become overloaded and the level of overloading depends on factors such as the amount of renewable generation dispatched in the Wagga North area, the amount of generation from Snowy Hydro, interconnector flows between NSW and VIC and the power flow in Line 63 towards Wagga Wagga.

[15] AEMO, 22 August 2024, *NEM Registration and Exemption List*. Accessed from: https://aemo.com.au/-/media/files/electricity/nem/participant_information/nem-registration-and-exemption-list.xlsx?la=en

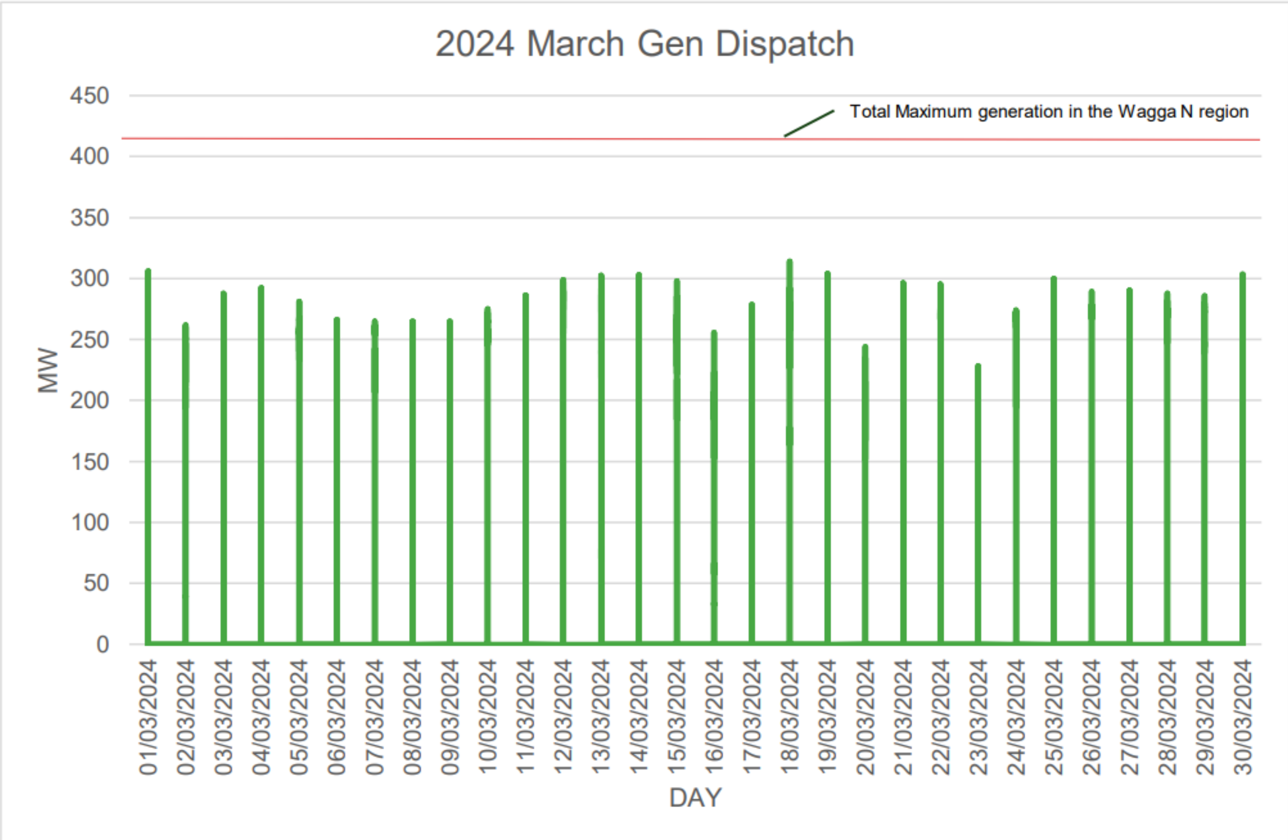
If the network is operated in its present configuration, a significant amount of renewable generation will need to be constrained at times of high output from the solar farms connected to Wagga North and in the Essential Energy network in the Temora region.

We have estimated the total generation required to be constrained to manage the potential thermal overloading of the Lines 9R6 and 9R5. To do this, we have simulated dispatch and price outcomes in the NEM using AEMO's Integrated System Plan (ISP) model. Our estimate is based on:

- AEMO's Step Change scenario from the 2024 ISP;
- the projected generation profile of the in-service and committed generators in the Wagga North area;
- demand forecasts for the Wagga North area; and
- the contribution factors of the renewable generators in the Wagga North area based on AEMO's Step Change central scenario from its 2024 ISP.

Figure 2-2 illustrates the total generation dispatch compared to the total maximum generation (409 MW) in the Wagga North area over a month due to system normal condition.[16]

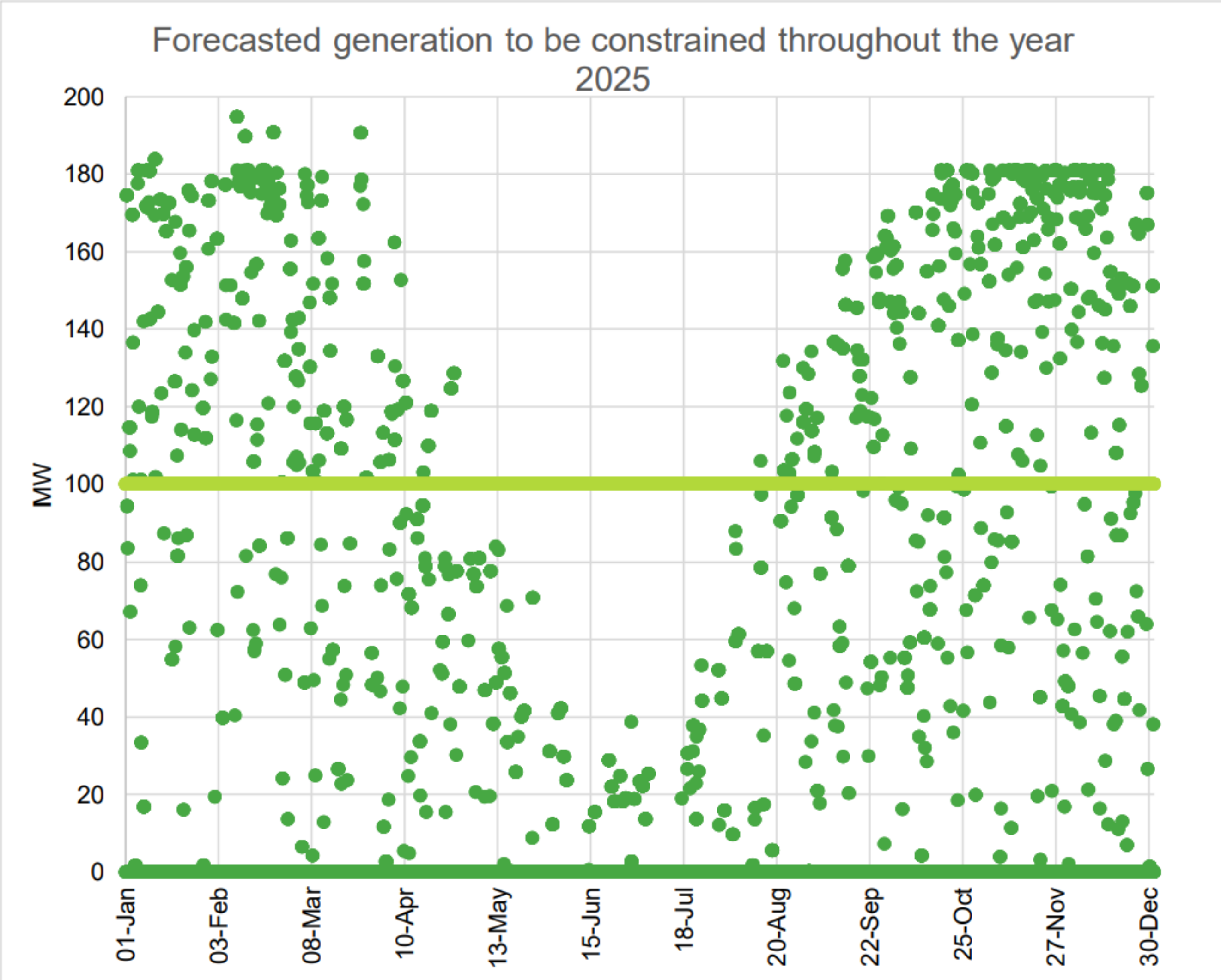
Figure 2-2: Total generation dispatch over a month in the Wagga North region



[16] The amount of constrained energy was estimated based on the projected solar traces and demand forecast data for the Wagga north area in the shoulder period. The projected solar traces of the in-service solar farms have been used to estimate solar traces of the committed generators located in the same geographical area.

Figure 2-3 demonstrates the estimated generation to be constrained throughout a year due to system normal overloading in Line 9R6. The modelling suggests that for approximately 191 days of the year it will be necessary to constrain at least 100 MW of renewable generation to ensure the line 9R6 loading level is maintained below its normal rating. In addition, Figure 2-3 shows that some level of constraint (even as low as a few MW) will be required for most of the year to manage the loading on Line 9R6 under system normal conditions.

Figure 2-3: Expected yearly generation to be constrained



2.3.4 Electricity generation and demand in the Wagga Wagga SAP

The Wagga Wagga Special Activation Precinct (SAP), a joint Government Agency initiative led by the Department of Premier and Cabinet and the Department of Planning and Environment has been announced. As part of Wagga Wagga SAP, potential large scale industrial development is expected in the area supplied by Wagga North substation, which comprises 4,424 hectares of land, located 8km north of Wagga Wagga, NSW[17]. The Precinct is being established as an economic and employment hub to

[17] NSW Department of Planning, Industry and Environment, May 2021, *Wagga Wagga Special Aviation Precinct Master Plan.* Accessed from: https://www.planningportal.nsw.gov.au/WaggaWaggaSAP

accommodate regionally significant industries and businesses on a large scale and will develop over 40 years.

The consultation process for the development of the SAP Master Plan shortlisted three land-use scenarios, which have associated power generation and load demand forecasts.[18] The descriptions of each of the three scenarios is as follows:

- **Scenario 4:** a 'high growth' scenario featuring a central area for low amenity 'stack' industries, close to the Riverina Intermodal Freight and Logistics (RiFL) hub;
- **Scenario 5:** a 'compact' scenario focussed on developing land north and south of Marino Drive. A Commercial Gateway precinct is also included along Bomen Road; and
- **Scenario 7:** a 'high growth' scenario where development is directed north and north-east. It incorporates industry zoned land north-east of Byrnes Road and also new land along Olympic Highway. Additional rail terminals are included north of RiFL.

The supporting Infrastructure and Services Plan[19] includes generation and load growth estimates for each of the scenarios as summarised below in Table 2-4.

Table 2-4: Estimated power generation and load growth under different scenarios of SAP

Scenario	Power generation (MW)	Average load demand (MW)
Scenario 4	342	241
Scenario 5	187	148
Scenario 7	398	282

The Wagga Wagga SAP project would be expected to reduce the constraints on Lines 9R5 and 9R6. However, the project is still in early stage of the development and the information about the potential renewable generation and load growth is not fully confirmed. The impact of the Wagga Wagga SAP will be assessed in the PACR through sensitivity analysis within the wholesale market modelling, contingent on the project reaching committed status.

2.4 Developments since the PSCR

2.4.1 Inclusion of a new BESS option

Some stakeholders to the PSCR raised the prospect that a BESS may help to address the identified need in the long run. In response to this, we have included an additional credible network option which involves the development of a 120 MW / 480 MWh BESS in the Wagga North area. For the purposes of this PADR, we have assumed that a BESS could be developed by Transgrid. As per other network options, our analysis estimates the development cost of a BESS and the market benefits associated with the BESS being added to the network.

[18] NSW Department of Planning, Industry and Environment, July 2020, *Wagga Wagga Special Activation Precinct; A.4.1a Structure Plan,* Accessed from: https://www.planningportal.nsw.gov.au/WaggaWaggaSAP

[19] NSW Department of Planning, Industry and Environment, July 2020, *Final Masterplan Report; Infrastructure and Services Plan; Wagga Wagga Special Activation Precinct.*, Accessed from: https://www.planningportal.nsw.gov.au/WaggaWaggaSAP

2.4.2 Upgrade to busbar at the 132/66 kV Wagga substation

Since releasing the PSCR, Transgrid has reviewed the rating of the busbars at the 132/66 kV Wagga substation. The older busbar, constructed from galvanised steel pipe, differs from Transgrid's current minimum standard aluminium tube design. This legacy busbar has a minimum summer day rating of 581 Amps, which is broadly equivalent to the rating of smaller 132 kV line conductors.

At present, loading on the busbar at Wagga substation is contained within its operational limits because the existing feeder lines restrict capacity to a level below that of the busbar. However, this RIT-T is assessing options to expand the capacity of feeder lines to Wagga substation. All of the options considered in the PSCR would increase feeder capacity to levels exceeding the rating of the busbar. Transgrid has identified that, under all of these options (Options 1-4 in this PADR), there will be times when load and/or generation must be constrained to ensure that the loading on the busbar does not exceed its designated rating. In effect, without upgrading the busbar at Wagga substation, market participants would not be able to utilise the full capacity of the new feeder lines. This means renewable generation in the Wagga North area would continue to face constraints after the line upgrade, now due to the busbar rather than the feeders.

Table 2-5: Existing busbar ratings at 132/66kV Wagga substation

Season	Time	Rating in Amps	
		Existing busbar	Rating per Wagga 132 kV feeder connected to busbar
Summer	Day	581	805
	Night	681	814
Autumn / Spring	Day	681	831
	Night	681	831
Winter	Day	681	879
	Night	1004	905

Transgrid considers that increasing the capacity of the busbar at Wagga substation will help to address the identified need for this RIT-T as it contributes to relieving constraints on renewable generation in the Wagga North area. In view of this, we have updated each of the PSCR options (Options 1-4 in this PADR) to include the cost of uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design). We consider that the upgrade to the feeder lines and the busbar at Wagga substation form an integrated solution to meet the identified need, in line with the AER's RIT-T application guidelines.

The estimated cost of the upgrading the busbar at Wagga substation is $6.55 million (FY2024/25). This cost has been incorporated into all options identified in the PSCR (Options 1-4 in this PADR) to ensure feeders are not constrained by the existing busbar rating. Since this upgrade is necessary for all these options, it has not changed the ranking of these options or the identification of the preferred option.

3. Consultation on the PSCR

We received seven submissions in response to the PSCR. Submissions from six parties have been published on our website. The remaining submitter requested confidentiality and so the details of this submission has not been included in this PADR or published on our website. We have outlined the key themes of these submissions below.

Stakeholders agreed with the identified need in the PSCR

Renewable generators in the Wagga North area identified that constraints on Lines 9R5 and 9R6 had caused adverse impacts including curtailment of renewable generation output, revenue loss due to these curtailments and investment uncertainty for additional renewable energy projects and BESS. IB Vogt agreed with the identified need and provided analysis of generation curtailment in the Wagga North area. It found that there is already substantial magnitude of curtailment occurring in Wagga North. Origin commented that significant growth in renewable generation in the Wagga North area had led to additional constraints and increasing network congestion.

Stakeholders viewed the main benefit as increased low-cost renewable generation in the NEM

Renewable generators in the Wagga North area noted that enabling more renewable output would allow the dispatch of low-cost renewable energy to displace higher-cost conventional generation. Some stakeholders provided quantitative estimates of the emissions not avoided due to the current constraints. The market modelling we have undertaken for this PADR captures the benefits that increasing renewable generation in the NEM has on reducing fuel costs and capital costs.

Origin suggested that Transgrid should incorporate involuntary load curtailment into the RIT-T's market benefit assessment. Origin stated that during high-value peak demand periods, current network constraints risk curtailment of otherwise available generation, increasing the potential for lost load. Transgrid's market modelling has captured the impact of the credible options on both voluntary and involuntary load shedding. Our analysis indicates that the impact on load curtailment is minimal principally because load in the base case is assumed to be met through other (higher cost) generation in the NEM.

Stakeholders generally expressed preference for Option 2

Renewable generators in the Wagga North area expressed clear preference for Option 2. Key reasons cited were that it has lower capital cost, quicker implementation timeline, sufficient increase in line capacity and reduced environmental and community impacts due to the use of existing corridors.

Two stakeholders suggested that while Option 2 addresses the current constraints, Option 3 or 4 might be more suitable to longer-term growth in the Wagga North area. Transgrid's market modelling analysis has indicated that Option 3 and 4 are unlikely to be net beneficial. IB Vogt considered that combining a network solution with a BESS would provide greater optional flexibility and long-term resilience. Transgrid's modelling accounts for commissioned and committed BESS in the NEM. We have also added a new option which involves installing a new 120 MW/480 MWh BESS in the Wagga North area.

We have also considered integrated solutions combining network (re-string) and non-network (BESS) projects. However, our analysis indicates that Option 5 (a standalone BESS) is not net beneficial (refer to Section 7.3). It follows that the BESS would not provide additional net benefit when deployed as an increment to a network option that addresses the constraint. As such, an integrated solution combining network and non-network projects were not progressed further.

The key matters raised in submissions relevant to the RIT-T assessment, as well as our responses and how the matters raised have been reflected in the PADR assessment are summarised in Appendix B.

4. Options that meet the identified need

This section describes the option(s) that we have explored to address the identified need, including the scope of each option and the associated costs. We consider that there are five technically and commercially feasible network options to address the identified need.[20]

Table 4-1: Summary of credible options ($m 2024/25)

Option	Description	Estimated capital cost[21]	Estimated capital cost of 132 kV busbar upgrade	Estimated total capital cost	Expected delivery time[22]
Option 1	Restring Lines 9R5 and 9R6 with a "Mango" ACSR/GZ[23] conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	14.3 (+/- 25%)	6.55 (+/- 25%)	20.82 (+/- 25%)	2027-28
Option 2	Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	12.5 (+/- 25%)	6.55 (+/- 25%)	19.09 (+/- 25%)	2027-28
Option 3	Construct a new double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	49.9 (+/- 25%)	6.55 (+/- 25%)	56.47 (+/- 25%)	2030-31
Option 4	Construct a new single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design	38.6 (+/- 25%)	6.55 (+/- 25%)	45.11 (+/- 25%)	2029-30
Option 5[24]	Develop a 120 MW / 480 MWh BESS in Wagga North area.	215.0 (+/- 25%)	N/A	215.00 (+/- 25%)	2027-28

This section provides further information on each of the credible options listed above.

4.1 Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PSCR compares the costs and benefits of each credible option to a 'do nothing' base case. The base case is the (hypothetical) projected case if no action is taken, i.e.:[25]

[20] As per clause 5.15.2(a) of the NER.
[21] For Options 1-4 this column presents the cost of the line upgrade component
[22] Delivery timeframes will be reviewed as part of the PACR and may change
[23] Aluminium conductor steel-reinforced cable.
[24] Cost estimates for Option 5 are drawn from AEMO data from the latest Input, Assumptions and Scenarios Report (IASR)
[25] AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, pp. 21.

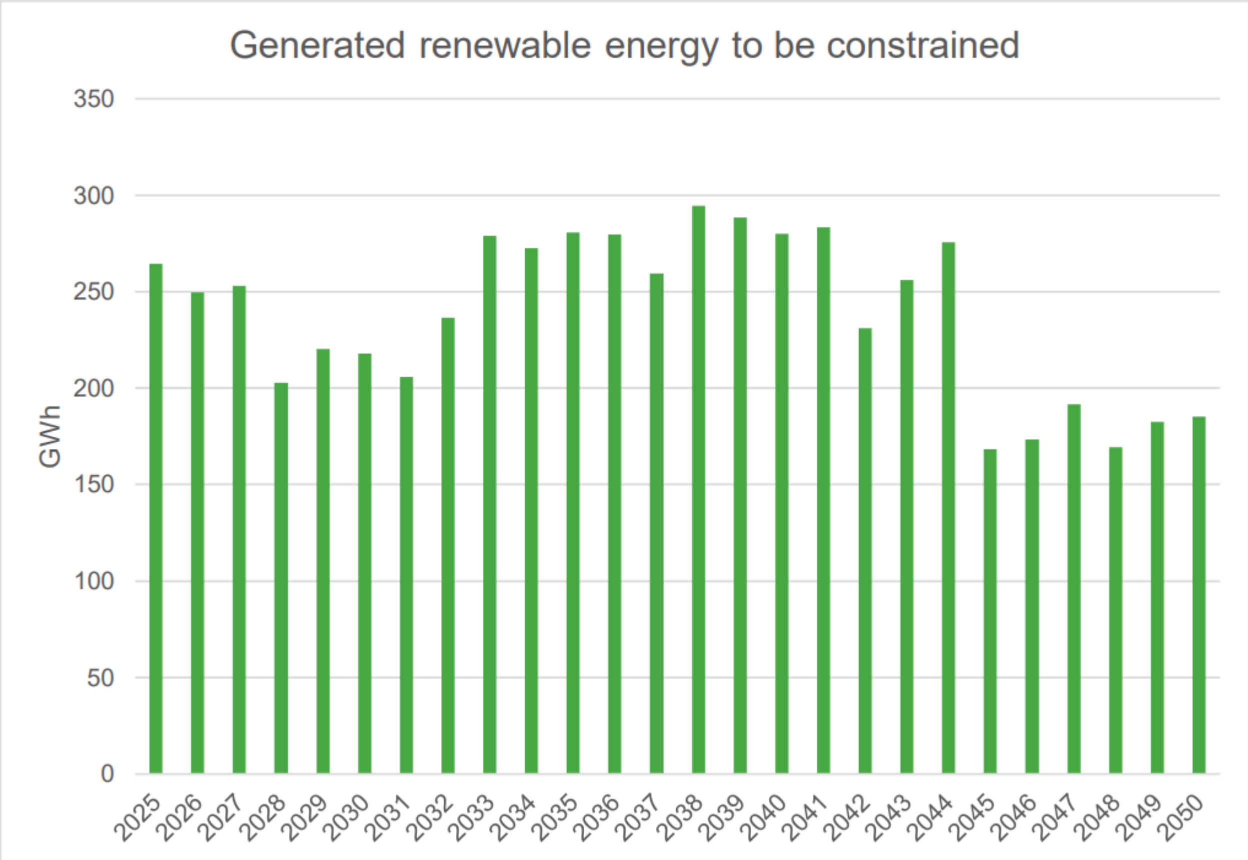
"*The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented*"

The base case considers a "do nothing" approach, where the existing network infrastructure is maintained, and the network is not augmented to account for increased renewable generation in the Wagga North area.

If the network is operated with the present configuration and as per current operating protocols, a significant amount of renewable energy will need to be constrained at times of high-generation output from the solar farms connected to Wagga North and in Essential Energy's network in the Temora region.

We have modelled the forecasted renewable curtailment on Lines 9R6 and 9R5, illustrated below in Figure 4-1our modelling suggests an average of approximately 240 GWh of renewable energy will be curtailed per annum from 2025 onwards.

Figure 4-1: Base case renewable generation curtailment.



As a result of the curtailment, reliance on existing higher cost generation and investment in new generation in other parts of the NEM will be required to meet expected load forecasts.

The assessment uses this base case as a common point of reference when estimating the net benefits of each credible option.

4.2 Option 1 – Restring Lines 9R5 and 9R6 with Mango ACSR/GZ conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design

Option 1 involves re-conductoring of lines 9R5 and 9R6 with a conventional larger diameter higher capacity conductor such as Mango ACSR/GZ. In comparison to the existing ratings of 125MVA/137MVA, re-stringing the lines should achieve minimum rating of 169 MVA. The total transfer capacity can be increased by at least 95 MW.

This is achieved by:

- Restringing 14.6km of Mango ACSR/GZ (or equivalent) conductor on Line 9R5 and 10.5km of Mango ACSR/GZ (or equivalent) conductor on Line 9R6 (including insulators and fitting replacements);
- Replacement of structures as required to meet structural and ground clearance requirements (approximately 60 structure replacements required);
- Performing associated structure strengthening on Line 9R5 and Line 9R6.

Option 1 also involves uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The estimated capital cost of the option is approximately $20.82 million ($2024-25) +/- 25 per cent, which is comprised of:

- $14.3 million ($2024-25) +/- 25 per cent for the line upgrade
- $6.55 million ($2024-25) +/- 25 per cent for the busbar upgrade

Table 4-2 shows the expected expenditure profile of this option. Annual operating expenditure is estimated at 0.5% of the forecast capital cost. This option is expected to take 31 months to complete, with commissioning possible in 2027-28.

Table 4-2: Option 1 expected expenditure ($m $2024-25)

Item	Estimated capital cost of line upgrade	Estimated capital cost of 132 kV busbar upgrade	Estimated total capital cost
FY26	1.11	0.87	1.98
FY27	9.20	5.57	14.77
FY28	3.96	0.10	4.06
Total capital cost	**14.27 (+/- 25%)**	**6.55 (+/- 25%)**	**20.82 (+/- 25%)**

4.3 Option 2 – Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade the busbar at 132/66 kV Wagga substation to aluminium tube design

Option 2 involves increasing Lines 9R5 and 9R6 normal ratings to a minimum of 223 MVA by restringing Lines 9R5 and 9R6 with a high-temperature, low-sag (HTLS) conductor of similar diameter, weight and tension capacity to the existing conductor. The use of a HTLS conductor of similar dimensions minimises the number of structure upgrades or replacements for structural reasons.

This is achieved by:

- Restringing 14.6km of Line 9R5 and 10.5km of Line 9R6 with a high-temperature, low-sag (HTLS) conductor, including insulators and fitting replacements;
- Replacement of structures as required for structural and ground clearance (estimated to be less than 10 structures in total for both lines 9R5 and 9R6).
- Performing associated structure strengthening on Line 9R5 and Line 9R6 as required.

Option 2 also involves uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The estimated capital cost of the option is approximately $19.09 million ($2024-25) +/- 25 per cent, which is comprised of:

- $12.54 million ($2024-25) +/- 25 per cent for the line upgrade
- $6.55 million ($2024-25) +/- 25 per cent for the busbar upgrade

Table 4-3 shows the expected expenditure profile of this option. Annual operating expenditure is estimated at 0.5% of the forecast capital cost. This option is expected to take 31 months to complete, with commissioning possible in 2027-28.

Table 4-3: Option 2 expected expenditure ($m $2024-25)

Item	Estimated capital cost of line upgrade	Estimated capital cost of 132 kV busbar upgrade	Estimated total capital cost
FY26	0.91	0.87	1.78
FY27	8.10	5.57	13.67
FY28	3.53	0.10	3.63
Total capital cost	**12.54 (+/- 25%)**	**6.55 (+/- 25%)**	**19.09 (+/- 25%)**

4.4 Option 3 – New double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design

Option 3 involves building a new double-circuit 132 kV transmission line from Wagga 330 kV substation to near Wagga North 132/66 kV substation.

This is achieved by:

- constructing approximately 14.6km of new double circuit 132kV transmission line from Wagga 330 substation to existing Line 991 Structure 613;
- diverting Line 991 to Wagga 330 substation on one side of the new double circuit transmission line;

- reusing the existing Line 991 from Structure 613 to Wagga North (WGN) to form the new feeder from Wagga 330 to Wagga North, utilizing the opposite side of the new double-circuit transmission line; and
- installing two new 132kV switch bays at the Wagga 330 substation.

Option 3 also involves uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The estimated capital cost of the option is approximately $56.47 million ($2024-25) +/- 25 per cent, which is comprised of:

- $49.92 million ($2024-25) +/- 25 per cent for the line upgrade
- $6.55 million ($2024-25) +/- 25 per cent for the busbar upgrade

Table 4-4 shows the expected expenditure profile of this option. Annual operating expenditure is estimated at 0.5% of the forecast capital cost. This option is expected to take 58 months to complete, with commissioning possible in 2030-31.

Table 4-4: Option 3 expected expenditure ($m $2024-25)

Item	Estimated capital cost of line upgrade	Estimated capital cost of 132kV busbar upgrade	Estimated total capital cost
FY26	2.82	0.87	3.69
FY27	5.41	5.57	10.98
FY28	20.3	0.10	20.40
FY29	15.2		15.20
FY30	6.19		6.19
Total capital cost	**49.92 (+/- 25%)**	**6.55 (+/- 25%)**	**56.47 (+/- 25%)**

4.5 Option 4 – New single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design

Option 4 involves building a new single circuit 132kV transmission line between Wagga North 132/66 kV substation and Wagga 330 kV substation.

This is achieved by:

- constructing approximately 14.9km of new single-circuit 132kV transmission line from Wagga 330 substation (WG1) to Wagga North substation (WGN), using 1 x Mango ACSR conductors supported by concrete poles;
- constructing one new 132kV switchbay at Wagga 330 substation; and
- constructing one new 132kV switchbay at Wagga North substation.

Option 4 also involves uprating the 132 kV busbars at the Wagga substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The estimated capital cost of the option is approximately $45.11 million ($2024-25) +/- 25 per cent, which is comprised of:

- $38.56 million ($2024-25) +/- 25 per cent for the line upgrade
- $6.55 million ($2024-25) +/- 25 per cent for the busbar upgrade

Table 4-5 the expected expenditure profile of this option. Annual operating expenditure is estimated at 0.5% of the forecast capital cost. This option is expected to take 48 months to complete, with commissioning possible in 2029-30.

Table 4-5: Option 4 expected expenditure ($m $2024-25)

Item	Estimated capital cost of line upgrade	Estimated capital cost of 132 kV busbar upgrade	Estimated total capital cost
FY26	2.15	0.87	3.02
FY27	4.29	5.57	9.86
FY28	8.06	0.10	8.16
FY29	24.06		24.06
Total capital cost	**38.56 (+/- 25%)**	**6.55 (+/- 25%)**	**45.11 (+/- 25%)**

4.6 Option 5 – Develop a 120 MW / 480 MWh BESS in Wagga North area

Following the feedback provided by stakeholders, we have included an additional network option which involves the development of a 120 MW / 480 MWh BESS in the Wagga North area.

The busbar upgrade included in Options 1-4 is not included in Option 5. The busbar upgrade is driven by increased line flows arising from higher line ratings under other network options. The BESS option does not increase flows to the Wagga 132 kV busbar because surplus generation in the Wagga North area will be used to charge the BESS. Therefore, the technically the busbar upgrade is not considered necessary for this BESS option.

For the purposes of this PADR, we have assumed that the BESS will be developed or commissioned by Transgrid.

The estimate capital cost of this option is approximately $215.00 million ($2024-25) +/- 25 per cent.

Table 4-6 shows the expected expenditure profile of this option. Annual operating expenditure is estimated at 1% of forecast the capital cost. This option is expected to take 48 months to complete, with commissioning possible in 2027-28.

Table 4-6: Option 5 expected expenditure ($m $2024-25)

Item	Estimated total capital cost[26]
FY26	107.50
FY27	107.50
Total capital cost	215.00 (+/- 25%)

The analysis undertaken in the preceding sections assumes that the BESS in Option 5 will be developed by Transgrid (i.e., Transgrid will incur the full cost of the BESS). An alternative option would be for Transgrid to procure network support services from a third-party BESS operator in the Wagga North region that will address the identified need.

Interested parties are invited to make submissions and the relevant details of the technical characteristics required for the non-network option are provided in Table 4-7 below.

Table 4-7: Summary of the technical characteristics required for the non-network option

Financial Year	Magnitude of power reduction on 9R5/9R6/911 cut-set (MW)	Expected cumulative exposure to overload per annum (hours)	Location	Time of the day
Initially from 2026 to 2027/28	Up to 120	> 605.3[27]	Located in connection points supplied by the Wagga North substation	Summer & Spring: 7:00 am to 5:30 pm Winter & Autumn: 8:00 am to 4:30 pm

4.7 Options considered but not progressed

We have also considered integrated solutions combining network (re-string) and non-network (BESS) projects. However, our analysis indicates that Option 5 (a standalone BESS) is not net beneficial (refer to Section 7.3). It follows that the BESS would not provide additional net benefit when deployed as an increment to a network option that addresses the constraint. As such, an integrated solution combining network and non-network projects were not progressed further.

[26] Capital cost for Option 5 is taken from AEMO's 2025 Inputs and Assumptions Workbook, assuming a 4-hour BESS.
[27] Annual hours taken from AEMO's 2023 annual constraint report

4.8 No material inter-network impact is expected

We have considered whether the credible options listed above are expected to have material inter-regional impact.[28] A 'material inter-network impact' is defined in the NER as:[29]

> "*A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.*"

By reference to AEMO's screening test for an inter-network impact,[30] a material inter-regional impact may arise if a credible option:

- is expected to change power transfer capability between transmission networks or in another TNSP's network by more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- is expected to result in an increase in fault level by more than 10 MVA at any substation in another TNSP's network; or
- involves either a series capacitor or modification in the vicinity of an existing series capacitor.

As none of these criteria are satisfied for this RIT-T, we consider that there are no material inter-network impacts associated with any of the credible options considered.

4.9 Community engagement

Transgrid is committed to reducing impacts on surrounding communities and landowners while continuing to work and maintain a safe and reliable transmission network.

Social licence may be achieved by early and continued engagement with communities and stakeholders who are reasonably expected to be affected by the project. Local knowledge can be crucial to finding the most appropriate solution.

Transgrid recognises that some of the options being considered in this RIT-T may impact the surrounding communities. Depending on the preferred option achieved through the RIT-T process. Transgrid will engage with stakeholders, including local landowners to understand community concerns and identify whether there are amendments to the options being considered, with a view to mitigating those concerns where possible.

Further, Transgrid will be engaging with communities post the RIT-T through other approval processes necessary to deliver the project effectively.

[28] As per clause 5.16.4(b)(6)(ii) of the NER.
[29] Definition of 'material inter-network impact,' in the Glossary to the NER.
[30] Inter-Regional Planning Committee. "*Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations*." Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

5. Materiality of market benefits

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[31]

5.1 Categories of market benefits that are considered material

The options considered in this PADR are expected to affect dispatch outcomes in the wholesale market, relative to the base case. The additional transmission capacity is expected to provide more efficient outcomes in the wholesale market, by increasing the output of low-cost renewable generation in the Wagga area and displacing higher cost conventional generation elsewhere.

The specific categories of market benefit that we consider may impact the outcome of this RIT-T are explained in further detail below.

5.1.1 Changes in fuel consumption in the NEM

This category of market benefit arises from changes in generation and storage dispatch outcomes within the NEM that result from the removal of network constraints relative to the base case. Under the base case, binding thermal constraints on Lines 9R5 and 9R6, together with capacity constraints at the 132/66 kV Wagga substation busbar, restrict the dispatch of renewable generation located in the Wagga North area. Consequently, higher-cost thermal generation must be dispatched to meet electricity demand. The credible options address these constraints and enable an increased volume of renewable generation to be dispatched from the Wagga North area. This additional renewable output displaces other generation in the NEM, which will change the aggregate cost of generation across the NEM.

5.1.2 Changes in costs for other parties in the NEM

This category of market benefit arises from changes in generation and storage dispatch outcomes within the NEM that result from the removal of network constraints relative to the base case. Under the base case, binding thermal constraints on Lines 9R5 and 9R6, together with capacity constraints at the 132/66 kV Wagga substation busbar, restrict the dispatch of renewable generation located in the Wagga North area. As a result, investment in additional generation capacity may be required to meet electricity demand in the future. The credible options address these constraints and enable an increased volume of renewable generation to be dispatched from the Wagga North area. This additional renewable output reduces or defers the need for the need for new investment in generation plants to meet growing electricity demand in the future.

5.1.3 Changes in Australia's greenhouse gas emissions

On 21 September 2023, the National Energy Laws were amended to reflect the incorporation of emissions reductions within the National Energy Objectives (NEO). Prior to the commencement of the amended Act, the NEO referred to the long-term interests of energy consumers with respect to price, quality, safety, reliability and security of supply of energy. The emissions reduction objective introduced by the Act adds reference to the long-term interests of energy consumers with respect to the achievement of targets set by

[31] NER clause 5.16.1(c)(6).

a participating jurisdiction for reducing Australia's greenhouse gas emissions, or that are likely to contribute to reducing Australia's greenhouse gas emissions.

Following this, the AEMC made harmonising changes to the National Electricity Rules, prompted by a rule change request from energy ministers, to ensure that network investment and planning frameworks are consistent with the new emissions reduction objective. The AEMC's Final Determination, published on 1 February 2024, included introducing a 'changes in Australia's greenhouse gas emissions' as a new class of market benefit to be considered within the RIT-T process.

The AER has updated the RIT application guidelines to provide guidance on how valuing emissions reduction is implemented.[32] The AER has also published an interim value of greenhouse gas emissions reduction (VER) which will apply to 30 June 2026 or until it is suspected, whichever is earlier.[33] We have applied this methodology to estimate the value of emissions reduction for each of the credible options.

5.2 Other categories of market benefits are not considered material

In addition to the classes of market benefits identified above, the NER also requires us to consider the following classes of market benefits, listed in the table below, arising from each credible option.[34] We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons set out below.

Table 5-1: Reasons non-wholesale electricity market benefits categories are considered not material

Market benefits	Reason
Changes in voluntary load curtailment	The identified need of this RIT-T is to relieve existing renewable generation constraints on Line 9R5 and Line 9R6, increasing the overall net market benefits in the NEM. This is expected to have an immaterial impact on load.
Changes in involuntary load shedding	
Changes in network losses	There is not expected to be any material difference in transmission losses between options.
Changes in ancillary services costs	While the cost of Frequency Control Ancillary Services (FCAS) may change, as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity, we consider that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option. There is no expected change to the costs of Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not considered material to the outcome of the RIT-T assessment.
Competition benefits	Competition benefits under the RIT-T relate to net changes in market benefits, arising from the impact of the credible option on the bidding behaviour of market participants in the wholesale market. While each of the credible options considered are designed to address network constraint, we consider that competition benefits are unlikely to be

32 AER, Application Guidelines Regulatory Investment Test for Transmission, November 2024, pp. 95
33 https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024
34 NER, clause 5.15A.2(b)(4)-(6).

Market benefits	Reason
	material and do not intend to estimate them as part of this RIT-T. This is due to all options being expected to have a similar effect on the wholesale market through relieving the existing constraint of Line 9R5, 9R6 and 991 in the Wagga North area. In addition, the calculation of competition benefits requires substantial additional market modelling. We consider that this modelling exercise would be disproportionate to any competition benefits that may be identified for this specific RIT-T assessment, particularly the difference between options in terms of competition benefits
Option value	Option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change. We note that no credible option identified is sufficiently flexible to respond to change or uncertainty. Additionally, a significant modelling assessment would be required to estimate the option value benefit but it would be disproportionate to potential additional benefits for this RIT-T. Therefore, we have not estimated any additional option value benefit.

6. Overview of the assessment approach

This section outlines the approach that we have applied in assessing the net benefits associated with each of the credible options against the base case.

6.1 The assessment considers three scenarios

The RIT-T is focused on identifying the top-ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world'). To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:

- the RIT–T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR, and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT–T instrument.

The credible options will be assessed under three scenarios in the PADR assessment, which reflect the scenarios from AEMO's 2024 ISP. AEMO defines these scenarios as[35]:

- ***"Green Energy Exports** features a very rapid decarbonisation rate to support Australia's contribution to limit global temperature rise to 1.5°C, including strong electrification and a strong green energy export economy.*
- ***Step Change** features an energy transition pace to support Australia's contribution to limit global temperature rise to less than 2°C, and compatible with 1.5°C outcomes depending on the actions taken across other sectors. Consumer energy resources provide a strong contribution to the transition.*
- ***Progressive Change** features more challenging conditions resulting in the transition speed focusing on Australia's current policies and global commitments to decarbonisation."*

At the time of preparing this report, AEMO's updated 2026 ISP Detailed Long-Term (DLT) model has not yet been released. Once the 2026 ISP model becomes available, the market modelling will be revisited and updated as part of the PACR stage to ensure alignment with the latest assumptions and scenarios.

Table 6-1 summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

[35] AEMO, 2024. *2024 Integrated System Plan (ISP)*. Accessed online: https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

Table 6-1: Summary of scenarios

Variable	Green Energy Exports	Step Change	Progressive Change
Capital costs	Base estimate	Base estimate	Base estimate
Demand	POE50	POE50	POE10
Renewable generation in the area	In-service and committed generators (as outlined in section 2.2)	In-service and committed generators (as outlined in section 2.2)	In-service and committed generators (as outlined in section 2.2)
Wholesale market benefits estimated	Transgrid estimate based on the 'green energy exports' 2024 ISP scenario	Transgrid estimate based on the 'step change' 2024 ISP scenario	Transgrid estimate based on the 'progressive change' 2024 ISP scenario
Discount rate	7.0%	7.0%	7.0%
Scenario weighting[36]	15.0%	43.0%	42.0%

6.2 Weighting of the reasonable scenarios

We have weighted each of the scenarios for this RIT-T using the weightings assigned in the 2024 ISP. These are as follows:

- 15 per cent to the Green Energy Exports scenario;
- 43 per cent to the Step Change scenario; and
- 42 per cent to the Progressive Change scenario.

The results are calculated for each scenario, as well as on a weighted basis.

6.3 Approach to estimating option costs

We have estimated the capital and operating costs of the options based on the scope of works necessary together with costing experience from previous projects of a similar nature.

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Advancement of Cost Engineering (AACE) classification system. Cost estimates are prepared in real dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

Routine operating and maintenance costs are based on works of similar nature

[36] Consistent with the scenario likelihoods outlined in AEMO's 2024 ISP.

6.4 Market modelling has been used to estimate the wholesale market benefits

We undertook wholesale market modelling using PLEXOS to model gross market benefits associated with the proposed options to enhance generation capacity in the region. Least-cost modelling, which is consistent with AEMO's approach to modelling the ISP, was adopted and wholesale market benefits were modelled for each option under each of the following ISP scenarios: Step Change, Progressive Change and Green Energy Exports.[37]

The RIT-T options were incorporated into AEMO's 2024 ISP Detailed Long Term (DLT) model and the gross market benefits for each option were calculated by estimating the following categories of costs for each Option and Base Case under all three ISP scenarios:

- Annualised build cost of new generation capacity installed (CAPEX)
  - > Annualised cost of new generation capacity installed in the model
- Total fixed, operation and maintenance (FO&M) costs
  - > The fixed cost component for operations and maintenance of generator units
- Total variable, operation and maintenance (VO&M) costs
  - > The variable cost component for operations and maintenance of generator units
- Total fuel costs for all generation capacity
  - > Costs associated with generator fuel consumption
- Total cost of voluntary load curtailment
  - > Payments made to demand-side participants who voluntarily curtail their load.
- Total cost of involuntary load curtailment
  - > Costs associated with unserved energy, which is defined as the load that cannot be met due to shortage of generation/ transmission capacity
- Transmission expansion costs associated with REZ development
  - > Costs associated with transmission network augmentations associated REZ development in the NEM
- Value of emissions produced
  - > The estimated value of emissions produced by all sources in the model.

The costs computed for each Option are then compared against the costs computed in the Base Case to determine the avoided costs i.e., market benefits associated with undertaking each option. The gross market benefits presented are computed half-hourly across a 20-year modelling horizon from 2024/25 to 2043/44. The annualised benefits are discounted to June 2024 using a 7% real, pre-tax discount rate which is consistent with the value applied by AEMO in the 2024 ISP.

[37] https://www.aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a6-cost-benefit-analysis.pdf

An overview of the methodology used for the wholesale market modelling, along with further details on key inputs and assumptions, is provided in Appendix C. A comprehensive discussion of our market modelling is set out in the accompanying supplementary market modelling report.

6.5 Assessment period and discount rate

The RIT-T will consider a 20-year period from 2024/25 to 2043-44. We consider that this takes into account the size, complexity and expected lives of the options and provide a reasonable indication of the costs and benefits over a long period.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling will include a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values will be calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

A real, pre-tax discount rate of 7.00 per cent has been adopted as the central assumption for the NPV analysis, consistent with AEMO's latest Input Assumptions and Scenarios Report (IASR).[38] The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.63 per cent.[39] We have also adopted an upper bound discount rate of 10 per cent (i.e., the upper bound in the latest IASR).[40]

6.6 Sensitivity and threshold analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. The factors tested as part of the sensitivity analysis in this PADR are:

- higher and lower capital cost assumptions for the credible options;
- alternate commercial discount rate assumptions;
- higher load forecasts; and
- higher forecast renewable generation capacity in the Wagga area

The results of the sensitivity tests are discussed in section 7.4. The sensitivity testing also includes 'boundary testing', where relevant, to investigate what key variables would need to change by in order to change the identified preferred option.

38 AEMO, *2025 Inputs, Assumptions and Scenarios Report*, Final report, August 2025, pp. 158.

39 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis, see: https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29/final-decision.

40 AEMO, *2025 Inputs, Assumptions and Scenarios Report*, Final report, August 2025, pp. 158.

7. Net present value results

This section outlines the assessment we have undertaken of the credible network options. The assessment compares the costs and benefits of each credible option to the base case.

7.1 Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case under each of the ISP scenarios.

Majority of the gross benefits are driven by cost savings for parties other than the RIT-T proponent (see Figure 7- 1). In particular, the avoided build cost (capex) of new generation capacity in the NEM relative to the Base Case.

The options allow for generation curtailment during peak solar output in the daytime in the Wagga region to be avoided which enables increased dispatch from existing nearby solar farms. This, in turn, reduces new solar capacity from being built or deferred across the NEM, particularly in Wagga and Southwest regions of NSW, relative to the Base Case. As such, new builds which would have been included in the Base Case are deferred or avoided.

Further detail on the market modelling results is available in the accompanying market modelling report.

Option 5 is forecast to deliver the highest gross benefits overall. Its benefits are consistently higher than the other credible options across all ISP scenarios, with an NPV of gross benefits of $81.1m (June 2025$) in the weighted scenario.

Option 1 and 2 also deliver high gross benefits, with an NPV of gross benefits of $24.9m (June 2025$) and $34.7m (June 2025$) in the weighted scenario, respectively.

Across the scenarios, Options 1, 2 and 5 deliver their largest gross benefits in the Green Energy Exports scenario, while Option 3 and 4 deliver their largest gross benefits in the Progressive Change scenario. On a weighted basis, Options 3 and 4 yield $13.2 million and $15.7 million, respectively, which are significantly below the levels forecast for Options 1, 2 and 5.

Table 7-1: NPV of gross economic benefits relative to the base case (June $2025 million)

Option	Step Change	Progressive Change	Green Energy Exports	Weighted
Option 1	28.03	19.62	30.43	24.86
Option 2	40.28	25.61	43.92	34.66
Option 3	10.90	17.91	6.46	13.18
Option 4	14.03	20.58	7.08	15.74
Option 5	78.40	77.15	99.78	81.08

7.2 Estimated costs

The table below summarises the present value of capital costs and operating and maintenance costs of each credible option relative to the base case. We only present one set of numbers as the costs are the same across all ISP scenarios.

Table 7-2: NPV of costs relative to the base case (June $2025 million)

Option	NPV of capital, operating and maintenance costs
Option 1	18.96
Option 2	17.39
Option 3	47.54
Option 4	38.08
Option 5	216.45

7.3 Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option relative to the base case under each of the ISP scenarios. The ranking of each option is consistent across each ISP scenario and the weighted scenario.

Table 7-3: NPV of net economic benefits relative to the base case (June $2025 million)

Option	Step Change	Progressive Change	Green Energy Exports	Weighted	Rank
Option 1	13.91	5.50	16.31	10.7	2
Option 2	27.33	12.66	30.97	21.7	1
Option 3	-21.36	-14.35	-25.80	-19.1	4
Option 4	-12.77	-6.23	-19.73	-11.1	3
Option 5	-122.81	-124.06	-101.43	-120.1	5

The figure below sets out the breakdown of the net economic benefits by category under the weighted scenario. The largest benefit under all options is the reduction in cost for parties other than the RIT-T proponent. This category is comprised of capital costs, fixed operating and maintenance cost, and variable operating and maintenance costs that are avoided or delayed relative to the base case. Option 2 has the lowest costs and the second highest gross benefits, resulting in it having the largest net economic benefits

Figure 7-1: Detailed NPV of net economic benefits under the weighted scenario (June $2025 million)

7.4 Sensitivity and threshold analysis

We have undertaken sensitivity testing to examine how the net economic benefits of the credible options changes with respect to changes in key modelling assumptions.

The factors tested as part of the sensitivity analysis in this PADR are:

- higher/lower capital cost assumptions for the credible options (undertaken on the weighted scenario);
- alternate commercial discount rate assumptions (undertaken on the weighted scenario).

In each case, we individually varied each factor identified above and estimated the net economic benefit in the scenario relative to the base case while holding other assumptions constant. The results of the sensitivity tests are set out in the sections below.

In addition, we have also undertaken a threshold analysis for Option 5 to consider the cost at which Transgrid could procure network support services from a battery proponent which would make a non-network solution a preferred option.

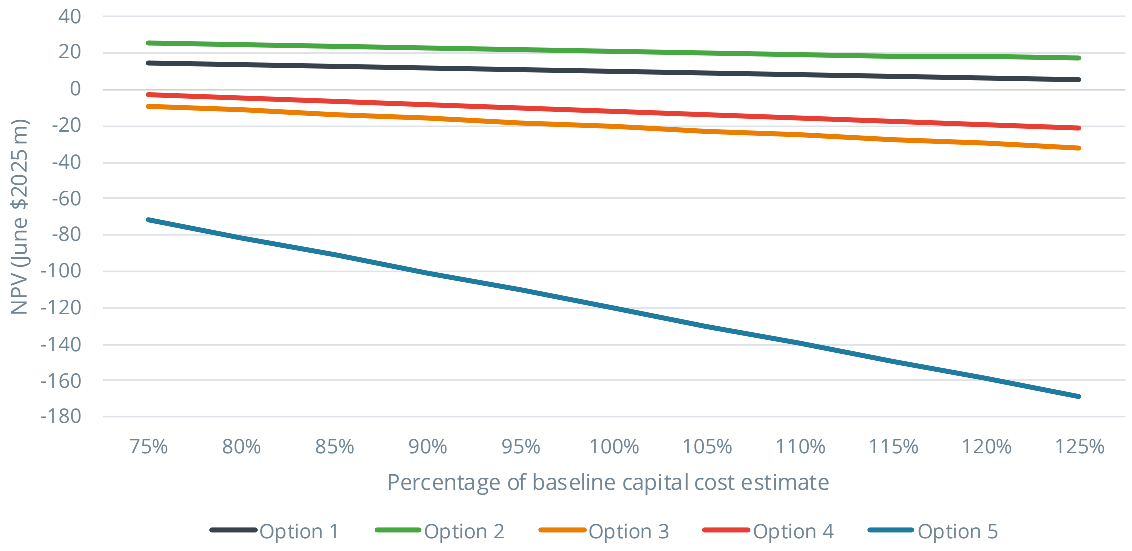
7.4.1 Sensitivity analysis on capital costs

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting capital costs that are 25% higher (the ‘High capex’ scenario) and 25% lower (the ‘Low capex’ scenario) than the estimate of capital costs adopted in our scenarios. Under both the low capex and high capex scenarios the relative rankings of the Options do not change. Furthermore, even in the Low capex scenario, Options 3, 4 and 5 deliver negative net economic benefits.

Table 7-4: NPV of net economic benefits relative to the base case with lower and higher capital costs (June $2025 million)

Option/scenario	Low capex	High capex	Rank
Sensitivity	*Estimate – 25%*	*Estimate + 25%*	
Option 1	15.26	6.22	2
Option 2	25.86	17.57	1
Option 3	-7.66	-30.51	4
Option 4	-1.96	-20.18	3
Option 5	-71.54	-168.72	5

Figure 7-2: NPV of net economic benefits relative to the base case with lower and higher capital costs (June $2025 million)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we consider whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome. Our findings show Option 2's capital costs would need to increase by more than 667% in order for its net benefits to decrease below that of Option 1.

7.4.2 Sensitivity analysis on discount rate

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 3.63%[41] and a high discount rate of 10.0% which aligns with the discount rate scenarios in the 2025

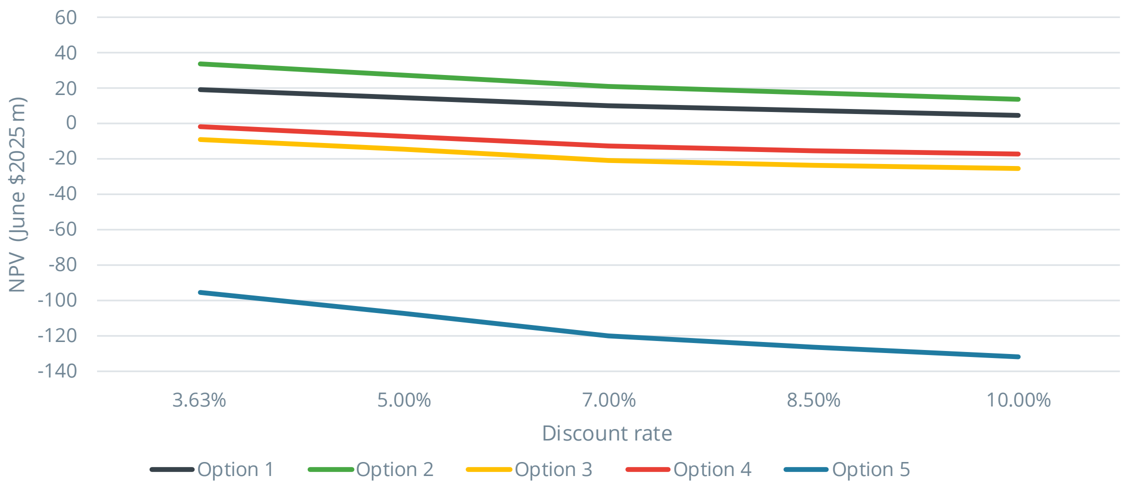
[41] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis, see: https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29/final-decision

IASR.[42] Under both the low and high discount rate scenarios, the relative rankings of the Options do not change.

Table 7-5: NPV of net economic benefits relative to the base case under lower and higher discount rates (June $2025 million)

Option/scenario	Low discount rate	High discount rate	Rank
Sensitivity	*3.63%*	*10.0%*	
Option 1	20.59	5.32	2
Option 2	34.52	14.38	1
Option 3	-6.20	-24.37	4
Option 4	0.09	-15.96	3
Option 5	-95.42	-131.46	5

Figure 7-3: NPV of net economic benefits relative to the base case under lower and higher discount rates (June $2025 million)



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result in Option 2 not being the preferred option. Our findings suggest that there are no realistic discount rates that would result in Option 1 surpassing Option 2 as the preferred option. Furthermore, we find Option 2 delivers positive net economic benefits relative to the base case at all reasonable discount rates.[43]

[42] AEMO, 2025 Inputs, Assumptions and Scenarios Report, August 2025, p.158
[43] This analysis can be found in the accompanying CBA model in tabs 'T2 Discount threshold - O1&2' and 'T3 Discount threshold - O2&3.

8. Conclusion

This PADR finds that Option 2 is the preferred option. Option 2 involves restringing Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrading the busbar at 132/66 kV Wagga substation to aluminium tube design.

Option 2 is the preferred option because it is the credible option that maximises the net present value of the net economic benefit.

The estimated net benefit of Option 2 is approximately $21.7m ($2024/25), under the weighted scenario and relative to a 'do nothing' base case. The estimated capital cost of this option is approximately $19.1m ($2024-25) +/- 25 per cent. Annual operating expenditure is estimated at 0.5% of the forecast capital cost. This option is expected to take 31 months to complete, with commissioning possible in 2027-28.

We consider that the analysis undertaken and the identification of Option 2 as the preferred option satisfies the requirements of the RIT-T in the NER.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PADR with the requirements of the National Electricity Rules version 241.

Rules clause	Summary of requirements	Relevant section
5.16.4 (k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Appendix B
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4 & 5
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 & 6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	5.3
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	7 & 8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	4 & 8
	(10) if each of the following apply to the RIT-T project: (i) the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project.	-

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Appendix B Summary of consultation on the PSCR

This appendix provides a summary of points raised by stakeholders during the PSCR consultation process, besides those comments considered confidential.

Summary of comments	Submitters	Our response
Stakeholders agreed with the identified need in the PSCR		
Renewable generators in the Wagga North area identified that constraints on Lines 9R5 and 9R6 had caused adverse impacts including curtailment of renewable generation output, revenue loss due to these curtailments and investment uncertainty for additional renewable energy projects and BESS.	Confidential submitter, p.1 Spark Renewables, p.1-2 Metlen (Wyalong), p. 2-5 Metlen (Junee), p. 2-5 Metlen (Wagga North), p.2-5	We have maintained the definition of the identified need in the PADR.
IB Vogt agreed with the identified need and provided analysis of generation curtailment in the Wagga North area for the 12-month period from 1 January 2024 to 31 December 2024. It found that there is already substantial magnitude of curtailment occurring in Wagga North.	IB Vogt, p.2-4	
Origin commented that significant growth in renewable generation in the Wagga North area had led to additional constraints and increasing network congestion.	Origin, p.1.	
Stakeholders considered that addressing the identified need would lower fuel costs and reduce emissions		
Renewable generators in the Wagga North area noted that enabling more renewable output would allow the dispatch of low-cost renewable energy to displace higher-cost conventional generation, improving market efficiency. Some stakeholders provided quantitative estimates on the emissions not avoided due to the current constraints.	Confidential submitter, p.1. Spark Renewables, p.2-3. Metlen (Wyalong), p.2-5 Metlen (Junee), p.2-5 Metlen (Wagga North), p.2-5	The market modelling we have undertaken for this PADR captures the benefits that increasing renewable generation in the NEM has on reducing fuel costs and capital costs

Summary of comments	Submitters	Our response
A stakeholder noted that avoided lost load should be considered a market benefit		
Origin Energy suggested that Transgrid should incorporate involuntary load curtailment into the RIT-T's market benefit assessment. Origin Energy emphasised that during high-value peak demand periods, current network constraints risk curtailment of otherwise available generation, increasing the potential for lost load. Origin Energy suggested that this benefit stream should be included in the modelling scenarios of the PADR.	Origin, p.1.	The market modelling we have undertaken for this PADR captures the impact of the credible options on both voluntary and involuntary load shedding. Our analysis indicates that the impact on load curtailment is minimal principally because load in the base case is assumed to be met through other (higher cost) generation in the NEM
Most stakeholders expressed preference for Option 2		
Renewable generators in the Wagga North area expressed clear preference for Option 2. Key reasons cited were that it has lower capital cost, quicker implementation timeline, sufficient increase in line capacity and reduced environmental and community impacts due to the use of existing corridors.	Confidential submitter, p.1 Spark Renewables, p.2 Metlen (Wyalong), p.6 Metlen (Junee), p.6 Metlen (Wagga North), p.6	Our analysis indicates that Option 2 is the preferred option because it is the credible option that maximises the net present value of the net economic benefit
Some stakeholders expressed that due to the expected growth in the region, a longer-term solution such as Option 3 or 4, while more expensive, could provide future proofing benefits.	Metlen (Wyalong), p.6 Metlen (Junee), p.6 Metlen (Wagga North), p.6 Origin p.1.	Our analysis indicates that Option 3 and 4 are unlikely to be net beneficial, principally due to the high cost associated with implementing these options.
Spark Renewables cited that a network solution would be a more reliable and predictable increase in transmission capacity, as compared to a BESS which can be affected by factors such as state of charge, ambient temperature, and operational strategies.	Spark Renewables, p.3	We acknowledge this comment.

Summary of comments	Submitters	Our response
Some stakeholders considered that hybrid network and non-network solutions should be explored		
IB Vogt's submission contained modelling of electricity flows under various scenarios including with a BESS and with HumeLink and Snowy 2.0. IB Vogt recommended a hybrid approach, combining network augmentation with a targeted non-network investment for operational flexibility and long-term resilience. IB Vogt noted that its BESS is expected to be commercially available from 1 July 2027.	IB Vogt, p1.	Our analysis accounts for commissioned and committed BESS in the NEM. We have also added a new option which involves installing a new 120MW/ 480 MWh BESS in the Wagga North area. We have also considered integrated solutions combining network (re-string) and non-network (BESS) projects. However, our analysis indicates that Option 5 (a standalone BESS) is not net beneficial (refer to Section 7.3). It follows that the BESS would not provide additional net benefit when deployed as an increment to a network option that addresses the constraint. As such, an integrated solution combining network and non-network projects were not progressed further.
Stakeholders urged urgency of implementation and prioritisation		
Renewable generators in the Wagga North area identified the urgency of addressing the identified need in their submissions, with some stakeholders calling for the implementation of the selected solution to be fast-tracked. Key reasons cited for urgency were that curtailment has already resulted in significant lost revenue for generators in the region, increased wholesale electricity prices for consumers, reduced investor confidence, and a delay in Australia's clean energy transition.	Confidential submitter, p.1-2. Spark Renewables, p2-3. Metlen (Wyalong), p.6 Metlen (Junee), p.6 Metlen (Wagga North), p.6	Transgrid is committed to ensuring the preferred option is implemented as quickly as is reasonably possible.

Appendix C Overview of the wholesale market modelling undertaken

The market modelling presented in this report is based on AEMO's 2024 Integrated System Plan (ISP) Detailed Long-Term (DLT) model, which provides a nationally consistent framework for evaluating long-term electricity system development. The modelling approach and input assumptions are aligned with AEMO's 2023 Inputs, Assumptions and Scenarios Report (IASR)[44], ensuring consistency with the latest planning and policy settings across the National Electricity Market (NEM).

Modelling Framework

The DLT model is a least-cost capacity expansion and dispatch model that optimises the development and operation of generation, storage, and transmission assets over a 20-year planning horizon (2024/25 to 2043/44). The model's objective function is to minimise the net present value (NPV) of total system costs, including build costs + production costs and fixed operations and maintenance costs

The model ensures energy balance, operational feasibility, and compliance with technical and policy constraints, including reliability standards, emissions targets, and renewable energy integration requirements.

Scenarios Considered

The network options were assessed under three core ISP development scenarios, each representing a distinct trajectory for Australia's energy transition specified in AEMO's ISP[45]:

Green Energy Exports: "reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation."

Progressive Change: "meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios."

Step Change: "achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in highly orchestrated CER, including electrification of the transportation sector".

[44] https://www.aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?rev=f6c9a6c48a9946208ab6e1cf7ef32c7f&sc_lang=en

[45] https://www.aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?rev=b811f5d66df24e0a980ce0df8eaa5687&sc_lang=en

Cost Categories Assessed

In accordance with the AER's RIT-T Guidelines, the following categories of system costs were calculated at half-hourly resolution across the modelling horizon:

- Annualised build cost of new generation capacity installed (CAPEX)
- Total FO&M costs
- Total VO&M costs
- Total fuel costs
- Total cost of voluntary load curtailment
- Total cost of involuntary load curtailment
- REZ Transmission expansion costs
- Value of emissions produced

Calculation of Gross Benefits

For each scenario, the gross market benefits of each network option are calculated as the difference in total system costs between the option and the Base Case (which assumes no additional network augmentation beyond committed projects). These benefits are aggregated over the 20-year modelling horizon and discounted to June 2025 using a 7% real, pre-tax discount rate, consistent with AEMO's ISP methodology.

The resulting gross benefits are then compared against the capital costs of each option to determine the net economic benefit and, subsequently, the preferred option. This cost-benefit analysis will be conducted as part of the Project Assessment Draft Report (PADR) using the inputs provided from this report.