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Maintaining Reliable Supply to the North West Slopes Area

RIT-T – Project Assessment Draft Report

Region: Northern New South Wales

Date of issue: 18 February 2022

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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.

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the North West Slopes area of northern New South Wales (NSW). Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process and follows the Project Specification Consultation Report (PSCR) and accompanying non-network expression of interest (EOI) released in April 2021.

The 'identified need' driving investment

As set out in our most recent Transmission Annual Planning Report (TAPR),[1] and our revenue proposal for the 2023-2028 period,[2] the latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward. This is mainly due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[3] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[4]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the forecast increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken. Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints, particularly during times of low renewable generation dispatch in the region.

Demand forecasts for the area have changed since the PSCR, due both an update from Essential Energy in terms of load in its network as well as a specific spot load forecast no longer being expected to proceed. We are therefore no longer considering the 'high' forecast from the PSCR and have made minor revisions to the central and low demand forecasts. However, our updated planning studies still show that the current network will not be capable of supplying the expected combined increases in load in the area without breaching the NER requirements going forward.

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

This RIT-T therefore assesses options to ensure the above NER requirements continue to be met in the North West Slopes area in light of the forecast demand increases. We consider this a 'reliability corrective

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1 Transgrid, *2021 Transmission Annual Planning Report*, p. 45, available at: https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf .

2 Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, pp. 44-45.

3 These levels are specified in Clause S5.1a.4.

4 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

The PADR analysis has benefited from stakeholder consultation

The PSCR and accompanying non-network EOI were released in April 2021. We did not receive any submissions directly to the PSCR but we did receive two responses to the EOI.

The non-network proponents who responded to the EOI requested confidentiality and so we have not reproduced any of their response material in the PADR, nor have we published the responses on our website.

In light of the removal of the high demand forecast and minor revisions to the other demand forecasts since the PSCR, during November 2021 we re-engaged with the two parties to confirm their continuing interest and to ensure appropriately sized, and costed, solutions were assessed in the PADR. This involved relaying the reduced requirements for non-network solutions under the revised demand forecasts and holding a number of discussions with proponents. Both parties that submitted to the EOI subsequently updated their proposals.

The credible options have been refined since the PSCR

The network options considered in the PADR remain the same as those set out in the PSCR.

Each of the credible network options includes the installation of a third 60 MVA 132/66 kV transformer at Narrabri, as the firm supply capacity of the existing transformers at this location is forecast to be exceeded under both demand forecasts used in this PADR leading to the reliability standard determined by IPART not being met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible option assessed that centre on:

- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and
- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale battery. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line running between Boggabri North and Narrabri.

Table E-1 below summarises each of the credible options assessed in the PADR.

Table E-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
	Uprating the existing line 969 from Tamworth to Gunnedah	
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million
	New single or double circuit transmission lines between Tamworth and Gunnedah	
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah.	• $74 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between Tamworth 330 and Gunnedah, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million

Option	Description	Estimated capex ($2020/21)
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $19 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah	• $74 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 and Gunnedah operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line		
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• $88 million
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah or Narrabri 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million

Option	Description	Estimated capex ($2020/21)
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million

While there have been no material changes to the network options since the PSCR, the non-network options have been refined to reflect:

- responses to the EOI, resulting in two new options being included that utilise Battery Energy Storage Systems (BESS) as put forward by proponents; and
- revised demand forecasts since the PSCR, which has led to the non-network components being resized and slightly rescoped.

The two non-network options, Option 5A and Option 5B, use BESS to provide a network support service. Option 5A and Option 5B vary by the size, number and location of the BESS.

The non-network solutions are not considered to be long-term standalone solutions and, instead, defer or avoid the rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North, as part of the preferred network option at this stage of the RIT-T (Option 3A). The details of these options have not been presented in this PADR to preserve the requested confidentiality by proponents.

Benefits from the options considered in this PADR

The key source of benefit expected for all credible options assessed in this PADR is avoided unserved energy to end consumers relative to the RIT-T 'base case', i.e., where action is not taken. Specifically, the current North West Slopes network is not capable of supplying the combined increases in load in the area and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. While the expected avoided unserved energy is substantial and will increase over time, we have capped it in the analysis so as to remove avoided unserved energy that is common to all options (since, including it, does not assist with identifying the preferred option overall), which is in line with the approach adopted in other RIT-Ts.[5]

Two of the credible options assessed involve the use of BESS, both of which have been proposed by third party proponents in response to the PSCR and accompanying EOI. These BESS components (which have been combined with network investment components to meet the overall identified need) are expected to be able to assist with providing reactive support in the short-term and also to use a portion of their capacity to dispatch to the wholesale market, replacing more costly generation that would otherwise be called on to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy that

[5] Section 6.1 outlines in more detail how the unserved energy that does not contribute to identifying the preferred option has been removed from the analysis.

all options provide. The wider wholesale market benefits associated with the BESS components of these options have been estimated using market modelling as part of this PADR.

Uncertainty has been captured by way of three scenarios

Uncertainty is captured under the RIT-T framework through the use of scenarios. The credible options have been assessed under three scenarios as part of this PADR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound, conservative estimate of the present value of net economic benefits;
- a 'central' scenario based on a central set of variable estimates and reflects the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions selected to investigate an upper bound of net economic benefits.

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table E-2: Summary of the three scenarios modelled

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast	Low demand forecast	Central demand forecast
New renewable generation in the area	All in-service and committed generators	All in-service, committed and advanced generators	All in-service and committed generators
Wholesale market benefits estimated	Estimated based on 'progressive change' 2022 ISP scenario	30 per cent lower than central scenario estimate	30 per cent higher than central scenario estimate
VCR	$46.93/kWh	$32.85/kWh	$61.01/kWh
Discount rate	5.50%	7.50%	2.23%

We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

The options involving non-network solutions in the short-term are preferred over the solely network options

The results of the PADR assessment find that the options involving non-network solutions in the short-term (i.e., Option 5A and 5B) are preferred over those based solely on network components. The options involving non-network solutions in the short-term are found to deliver estimated net benefits of approximately $507 million to $540 million overall on a weighted basis across the scenarios, relative to the base case 'do nothing' option, which compares to $410 million for the top-ranked solely network option (Option 3A).

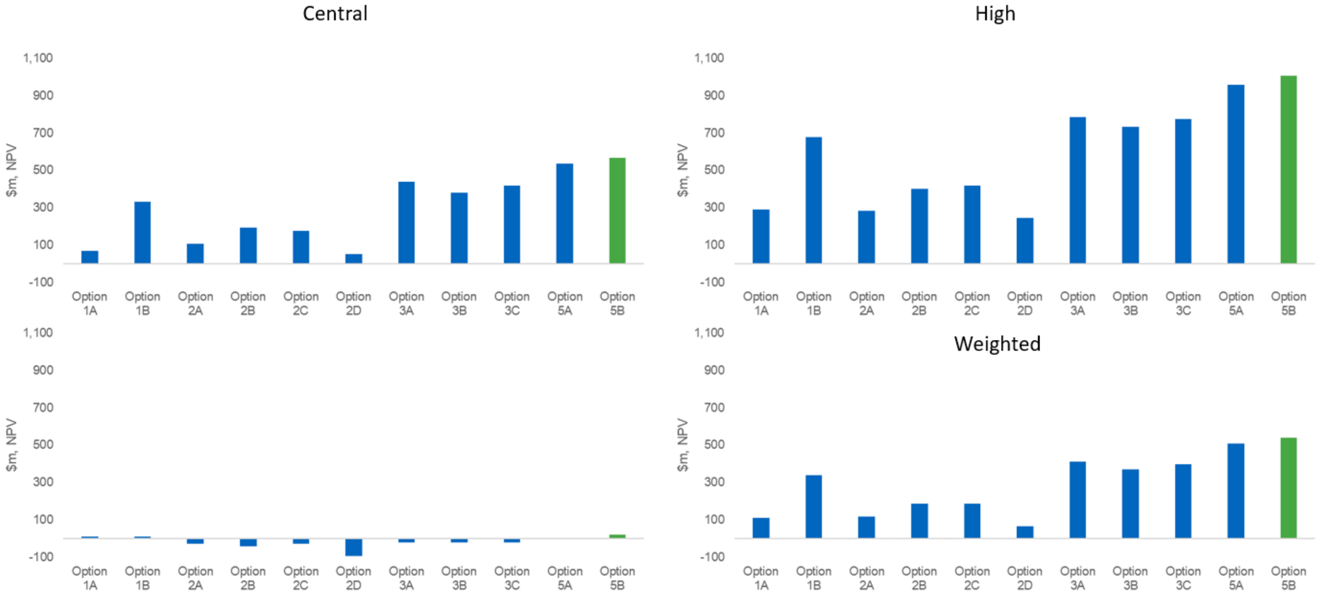
Option 5B is the top-ranked option overall, with net benefits that are approximately 6 per cent greater than the second ranked option (Option 5A) and 32 per cent greater than the top-ranked solely network option (Option 3A).

Option 3A has the second lowest expected total cost of the solely network options in present value terms under the weighted results. However, it can be constructed more quickly and so can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[6] Option 3A is therefore considered the preferred network option at this stage of the RIT-T and is the network option the non-network options have been coupled with.

Figure E.1 shows that, while the level of net benefits differs across the three scenarios, Option 5B is always the top-ranked option by a material margin (between 5 and 92 per cent). Option 5A is the second-ranked option in all scenarios besides the low scenario, where Option 1A and Option 1B are marginally ahead of Option 5A. Option 5A and Option 5B have greater net benefits than the solely network options on a weighted basis due to these options being able to be commissioned approximately one to three years before the network options, which allows them to avoid substantial additional unserved energy in these earlier years.

[6] The present value of all capex and opex of Option 3A under this scenario is $101 million, which compares to $87 million for Option 2B.

Figure E.1: Summary of the estimated net benefits



Almost all of the estimated gross benefits are derived from avoided unserved energy, which make up approximately 89 per cent of the total gross benefits of Option 5B on a weighted basis. However, the estimated wider wholesale market benefits are found to not be material to the overall outcome and, if removed from the assessment, would not change the ranking of the options under the central scenario, high scenario or on a weighted basis.[7]

Option 5B is considered the preferred option and the option that satisfies the RIT-T at this stage of the process. However, we note that this conclusion is highly dependent on the assumed timing of Option 5B compared to Option 3A (and Option 5A), as discussed further below.

Assumed option timing is a key driver of the preferred option (and will be further investigated ahead of the PACR)

A key determinant of the overall preferred option is the assumed build times, and ultimate commissioning dates, of each of the credible options. Options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided in earlier years.

Sensitivity analysis undertaken as part of this PADR shows that the results are relatively sensitive to the assumed commissioning dates for the options, e.g., if Option 3A was to be delivered a year earlier, and Option 5B remained on the same timing, then Option 3A would have almost the same benefit as Option 5B.

While the timing sensitivities undertaken in this PADR are focused in particular on the rankings between the network and non-network options (rather than between the non-network options), we note that the assumed timings are also likely to be a key driver of the rankings between the non-network options.

We will therefore be focussing, internally and with third party proponents of non-network solutions, to firm up the assumed commissioning dates (and costs) for all options between now and the PACR, and to

7 If wholesale market benefits are removed from the low scenario, Option 5B and 5A would go from being ranked 1st and 4th, respectively, to being ranked 6th and 10th, respectively.

ensure that the assumed option timing is realistic in all cases. We expect that factors such as the assumed timing of land acquisition and planning approvals will be key to firm up and note that the current proposals from third parties display some diversity across these assumptions. It is expected that the assumed option timings in the PACR will reflect what option proponents are willing to commit to.

Next steps

We welcome written submissions on this PADR. Submissions are due on 7 April 2022.

Submissions should be emailed to our Regulation team via Regulatory.Consultation@transgrid.com.au.[8] In the subject field, please reference 'PADR Maintaining Reliable Supply to the North West Slopes Area project.'

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 a PACR. The PACR is expected to be published in June 2022.

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Contents

1. Introduction

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As set out in our most recent Transmission Annual Planning Report (TAPR), and our revenue proposal for the 2023-2028 period,[9] the latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward.[10] This is mainly due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

Our power system studies forecast that the expected load growth will reach voltage stability and thermal limits in the next few years on the 132 kV supply network in the North West Slopes area if action is not taken.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[11] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[12]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints going forward, particularly during times of low renewable generation dispatch in the region.

This RIT-T therefore examines various network and non-network options for relieving these constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market.

As stated in our revenue proposal for the 2023-2028 period,[13] we will include the preferred option identified through the RIT-T in our augmentation expenditure forecast in our Revised Revenue Proposal for the forthcoming regulatory period. More information on our 2023-28 revenue proposal can be found here.

9 Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, pp. 44-45.

10 Transgrid, *2021 Transmission Annual Planning Report*, p. 45, available at: https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf .

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12 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

13 Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, p. 112.

1.1. Purpose

The purpose of this PADR is to:

- confirm the identified need for the investment, and describe the assumptions underlying this need, including the changes that have led to the most recent demand forecasts;
- 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. We also describe how the options have been modified in light of revised demand forecasts since the PSCR;
- identify and confirm the market benefits expected from the various credible options;
- present the results of the NPV analysis for each of the credible options assessed;
- 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.

Overall, this report provides transparency into the planning considerations for investment options to ensure continuing stability of the North West Slopes area power system, 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.

The credible options outlined in this PADR have been developed as part of our long-term planning for the area and each involves a series of investments over the next twenty years. This RIT-T assesses all stages of these options in order to identify the most efficient series of investments to meet network needs over the long-term.

1.2. How to make a submission and next steps

We welcome written submissions on this PADR. Submissions are due on 7 April 2022.

Submissions should be emailed to our Regulation team via Regulatory.Consultation@transgrid.com.au.[14] In the subject field, please reference ‘PADR Maintaining Reliable Supply to the North West Slopes Area project.’

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.

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2. Benefits from improving the stability of the North West Slopes power system

This section outlines the key benefits expected from the various options assessed in this PADR for improving the stability of the North West Slopes power system.

It first summarises and updates the 'identified need' for this RIT-T, before outlining the updated demand forecasts since the PSCR and setting out how the non-network options put forward in responses to the EOI are expected to be able to provide additional sources of market benefit.

More information on the current network area is provided in Appendix B.

2.1. Summary of the 'identified need'

Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[15] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[16]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the forecast increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints, particularly during times of low renewable generation dispatch in the region.

Demand forecasts for the area have changed since the PSCR, due both an update from Essential Energy in terms of load in their network as well as a specific spot load forecast no longer being expected to proceed, as described more fully below. However, our updated planning studies still show that the current network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements going forward.

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

This RIT-T therefore assesses options to ensure the above NER requirements continue to be met in the North West Slopes area in light of the forecast demand increases. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

In response to non-network EOI that accompanied the PSCR, this PADR assesses a number of options involving non-network solutions that can not only meet the voltage requirements but also provide a range of

15 These levels are specified in Clause S5.1a.4.
16 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

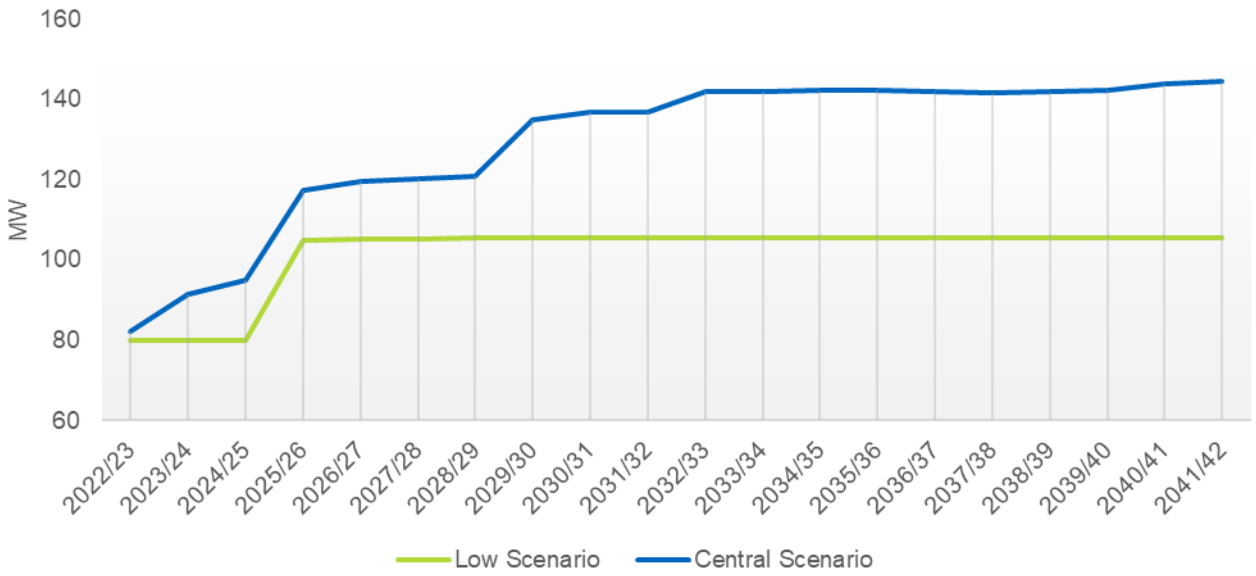
wider wholesale market benefits. The source of the expected benefits for these options is discussed in section 2.3 below.

2.2. Demand forecasts have been updated since the PSCR

Demand forecasts are a key driver of the identified need for this RIT-T and are expected to increase significantly in the North West Slopes power system due to both underlying general load growth as well as specific spot load developments coming online – the Narrabri Gas Project and the Vickery Coal Mine (VCM).

The PADR has considered two demand forecasts (the central and low forecasts) representing different assumed quantities, timings and locations for key loads.

Figure 2: Peak demand forecasts for the North West Slopes area



The third demand forecast from the PSCR (i.e., the high demand forecast) no longer features in the assessment as the confidential mining load that drove this scenario (and was the only difference between the central and high demand forecasts at that point in time) is no longer expected to connect. The 'high economic benefits' scenario investigated in this PADR therefore applies the central demand forecast (as outlined in section 5.1 below), rather than the previous high demand forecast.

Following the release of the PSCR, Essential Energy informed us of a minor change to the expected load for the Santos Narrabri Gas Project (the details of which have been kept confidential). This change has been reflected in both demand forecasts used.

There has been no change since the PSCR to the central demand forecasts provided by Essential Energy for the other key spot load in the area, Whitehaven Coal Limited's VCM, which was approved by the Independent Planning Commission of NSW in August 2020 and is expected to connect to the distribution network.[17] However, it has been removed from the low scenario to test a greater variation in demand forecasts as part of this PADR.

The two key spot loads are reflected in the demand forecasts used in this PADR as follows:

- Central forecast:
  - assumes that both VCM and the Narrabri Gas Project connect; and
  - assumes the full forecast for the Narrabri Gas Project (Stages 1 and 2).
- Low demand forecast:
  - VCM does not connect;
  - only Stage 1 of the Narrabri Gas Project is assumed to connect.[18]

The demand forecasts therefore reflect the various stages of potential development for the key loads and allow the PADR to assess how the net benefit of the options considered varies depending on differing assumptions around the progression of later development stages.

Essential Energy have also provided revised general demand forecasts for the region as part of an annual update. While each region continues to show load growth, it is at a lower rate than the forecasts available at the time of the PSCR (these revised forecasts have also been reflected in our 2021 TAPR).

2.2.1. Updated forecast voltage and thermal limits if action is not taken

The changes in the load forecasts have had a minor impact on the forecast voltage and thermal limits if action is not taken. Specifically, our system studies continue to show that the available capacity in the North West Slopes area is limited following connection of the Narrabri Gas Project by:

- thermal constraints on line 969 (Tamworth to Gunnedah) under system normal conditions; and
- voltage stability constraints between Gunnedah and Narrabri for a contingent outage of line 969 or 968 (Tamworth to Narrabri).

Figure 2-3 shows the updated voltage limits for the North West Slopes area considering the maximum demand that can be supplied without resulting in network voltages below 0.9 pu, under system normal and under (N-1) contingency conditions, along with the thermal limit due to the increased demand.

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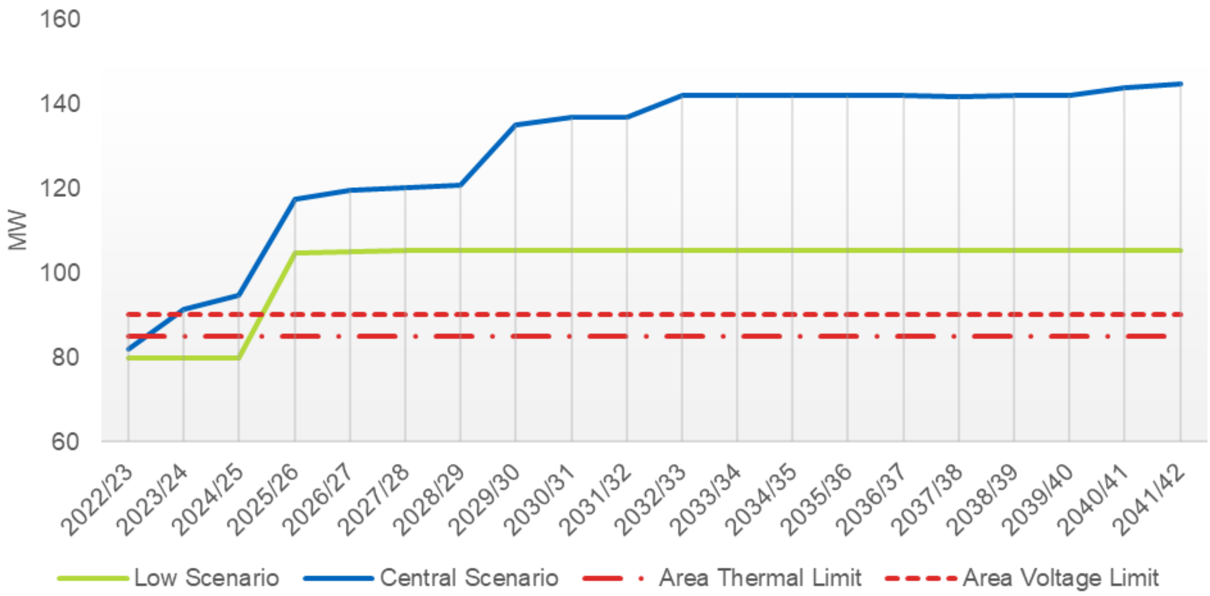
[17] Australian Mining Monthly, *Vickery extension on track for 2021 construction completion,* 8 June 2019, available at: https://www.miningmonthly.com/development/international-coal-news/1364804/vickery-extension-on-track-for-2021-construction-completion; and Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Introduction*, p 1-1, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213410.742%20GMT.

[18] The development of the gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline could affect the later stages of the Narrabri Gas Project, See Appendix B for detail on the potential gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline.

Figure 2-3: Peak demand forecast with voltage and thermal limits



The voltage stability constraint occurs for a trip of line 969, and is expected by 2023/24 and 2025/26 under the central and low demand forecasts, respectively.

The thermal constraint on line 969 due to the inclusion of stage 1 of the Narrabri Gas Project in 2025/26 can occur during system normal conditions or a contingent outage of line 968 under both demand forecasts when there is limited generation in service in the area to offset the load. It can also occur during system normal conditions from 2029/2030 onwards under the central forecast following the inclusion of stage 2 of the Narrabri Gas Project, even with more generation in service.

The thermal constraint is expected to occur from the inclusion of VCM earlier in the forecast period but can also be temporarily managed by operational measures until stage 1 of the Narrabri Gas Project comes online.

Under the central forecast, the voltage constraints are expected to worsen from 2025/26 onwards. Voltages at Narrabri and Gunnedah would be further outside of the planning criteria set out in Schedule 5.1.4 of the NER for an outage of one of the 132 kV transmission lines supplying Narrabri and Gunnedah from Tamworth (lines 968 or 969).

If action is not taken, voltages in the area will drop to unsustainable levels and voltage collapse could occur in the region following a contingency on line 969 due to insufficient dynamic reactive support in the region under both demand forecasts. This voltage collapse could lead to significant amounts of load being shed throughout the North West Slopes area.

Under both demand forecasts outlined in this PADR, the load increase at the Narrabri substation leads to the firm supply capacity for the transformers at this location being exceeded. This will result in the IPART reliability standard not being met.

2.3. Wholesale market benefits expected from the use of non-network solutions

Two of the credible options assessed in this PADR involve the use of Battery Energy Storage Systems (BESS), both of which have been proposed by third party proponents of these solutions in response to the EOI that accompanied the PSCR. These components are expected to be able to assist with providing reactive support in the short-term but could also use a portion of their capacity to dispatch to the wholesale market, offsetting more costly generation that would otherwise be called to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy that all options provide.

These wider benefits have been estimated by way of wholesale market modelling conducted by EY and are found to be made up primarily of avoided and deferred capital costs of new generation and storage and avoided generator dispatch costs. However, they are also found to ultimately not be material to the outcome of this PADR in terms of which options are top ranked overall (as outlined in section 7).

While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options. Specifically, while this additional capacity may affect the investment decisions of future local renewable generators on the 132 kV network, upstream 330 kV network constraints outside of this RIT-T (particularly south of Tamworth) mean that any new generation is not expected to displace the output of generation elsewhere and so there is not expected to be any material wider wholesale market impacts between the options and the base case. As a consequence, these credible options do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market.

None of the options are expected to add to, or takeaway from, any wholesale market benefits from future expansions of QNI over the longer term (e.g., ‘QNI Connect’ referred to in the draft 2022 ISP). These future upgrades of QNI are expected to be 330 kV and will not tie into the 132 kV network in the North West Slopes (despite likely passing nearby).

3. Consultation on the PSCR

The PSCR and accompanying non-network EOI were released in April 2021. We did not receive any submissions directly to the PSCR but did receive two responses to the EOI.

The non-network proponents who responded to the EOI requested confidentiality and so we have not reproduced any of their response material in the PADR, nor have we published the responses on our website.

In light of the removal of the high demand forecast and minor revisions to the other demand forecasts since the PSCR, during November 2021 we re-engaged with the two parties to confirm their continuing interest and to ensure appropriately sized, and costed, solutions were assessed in the PADR. This involved relaying the reduced requirements for non-network solutions under the revised demand forecasts and holding a number of discussions with proponents. Both parties that submitted to the EOI subsequently updated their proposals.

4. Credible options assessed

This PADR assesses both network and non-network options.

The network options remain the same as those discussed in the PSCR.

Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded under both demand forecasts and to ensure the reliability standard set by IPART is met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options assessed differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible option assessed that centre on:

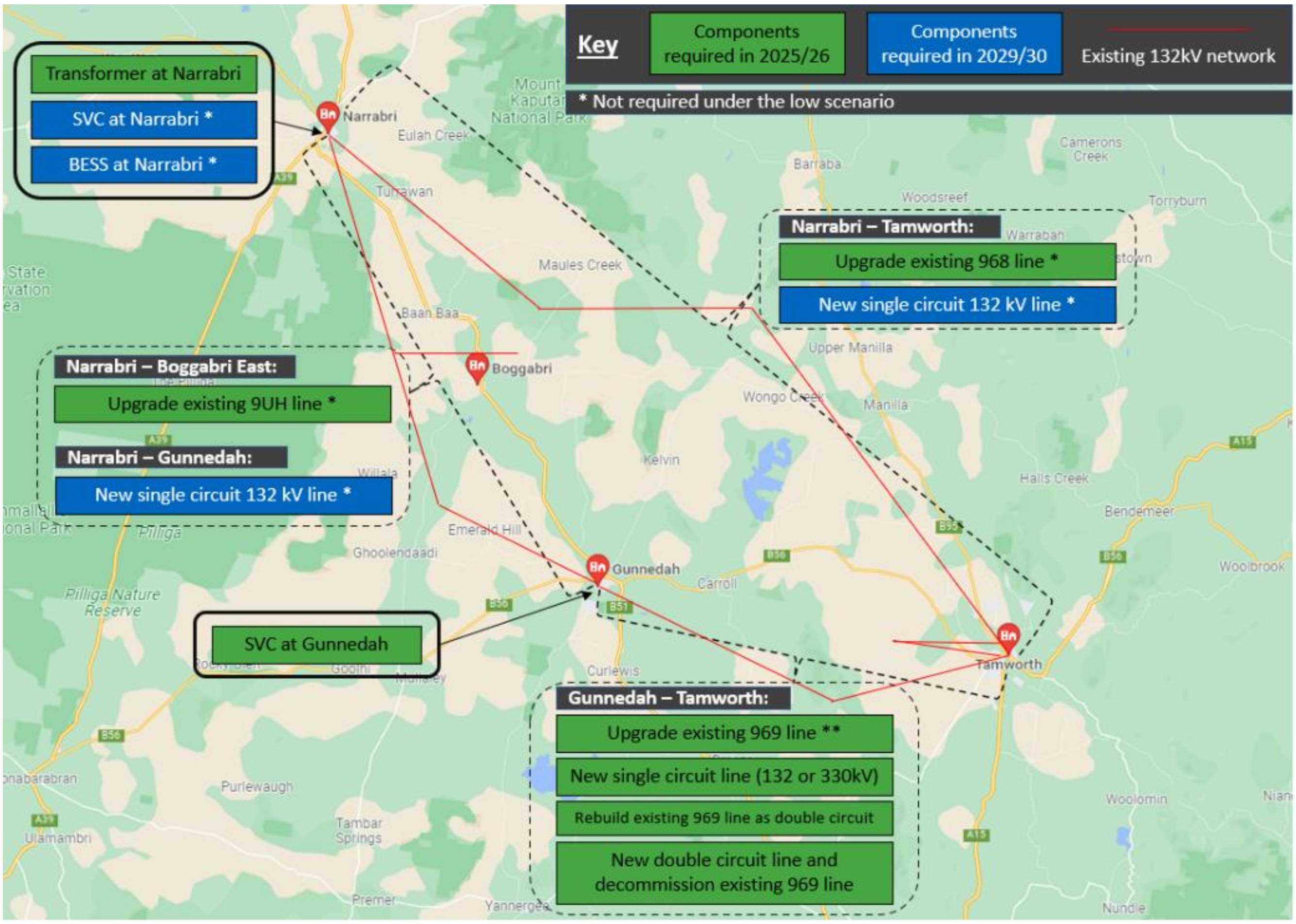
- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and
- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale BESS. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line.

Figure 4 below illustrates the various components that make up the credible network options. Specifically, it shows the technology and location of the components that can assist with both the short-term and longer-term voltage support required. While the credible options reflect different combinations of these components, we note that not all components can be coupled together to form credible options (and the earlier components can impact the choice of the later component(s)).

All locations shown in the figure below, and all figures in this section, have been included purely for illustrative purposes and are not intended to denote specific locations or line routes.

Figure 4: Various components the credible network options involve



*** While the upgrade of the 969 line between Gunnedah and Tamworth to 160 MVA is required under the low and central scenario for Options 1A and 1B, it is only required under the central scenario and to 135 MVA for Options 2A, 2B, 2D and 4.*

While there have been no material changes to the network options since the PSCR, the non-network options considered in the PADR assessment have been refined to reflect:

- submissions to the EOI, resulting in two new options being included that utilise BESS; and
- revised demand forecasts since the PSCR, which has led to the elements of the non-network options being resized and rescoped.

As outlined in section 4.4, both of the non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line when the Narrabri Gas Project comes online, which is part of the preferred network option at this stage of the RIT-T (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to ensure the reliability standard set by IPART is met at Narrabri. The two non-network options therefore reflect a combination of an initial non-network component and a third Narrabri transformer in all scenarios, followed by a deferred rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North in the central and high scenarios when the Narrabri Gas Project comes online.

Table 4-1 below summarises each of the credible options assessed in the PADR. All options are considered to meet the identified need from a technical, commercial, and project delivery perspective.[19] As outlined in section 7.5.1, the assumed timing of each option is expected to be a key determinant of the ultimately preferred option and will be further investigated as part of finalising the PACR.

While all potential stages of each option are shown in Table 4-1, some of the later stages are not required over the assessment period for the low demand forecast and are only relevant for the central demand forecast (in the later years of the assessment period). The timing of the initial stage for all options has been fixed across the two demand forecasts (since these stages effectively need to be committed to now to ensure commissioning in time under the central forecast), while the timing of the later stages varies by forecast depending on when they are required (since they do not yet need to be committed to). The individual option sections below detail the specific timing assumed for each stage of each option under the two demand forecasts.

Table 4-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
Uprating the existing line 969 from Tamworth to Gunnedah		
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million

[19] As per clause 5.15.2(a) of the NER.

Option	Description	Estimated capex ($2020/21)
	New single or double circuit transmission lines between Tamworth and Gunnedah	
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah.	• $74 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between Tamworth 330 and Gunnedah, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $19 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah	• $74 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 and Gunnedah operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $38 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
	Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line	
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million

Option	Description	Estimated capex ($2020/21)
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• $88 million
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah or Narrabri 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million

Capital costs for the network options have been revised since the PSCR to reflect current market trends and risks, drawing on the experience of recent projects. All network options are assumed to have annual operating and maintenance costs equal to approximately two per cent of their capital costs.

The costs of the non-network options have been incorporated in the PADR assessment in line with the guidance provided by the AER as part of its 2020 update of the RIT-T Application Guidelines.[20] In particular, since the non-network options do not involve currently committed or anticipated projects (as defined in the RIT-T) the PADR assessment reflects:

- the proposed network support cost as the cost of the option;
- the same network support cost as a benefit to the option proponent; and
- the full capital and operating costs of the option as part of the 'costs for parties other than the RIT-T proponent' category of market benefits.

The market benefits associated with the operation of the non-network solutions outside of the times needed for network support have also been reflected in the assessment of market benefits (see section 6.3).

[20] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

The remainder of this section provides further detail on each of the credible options assessed. It also outlines further options that have been considered but not progressed (and the reasons why).

Appendix C provides the indicative ultimate layouts, via line diagrams, for all elements of the options.

4.1. Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

This option involves uprating the existing line 969 and the two variants test different line augmentations and dynamic reactive support levels at Narrabri and Gunnedah.

The scope of the various elements for Option 1A and Option 1B is shown in Table 4-1 above.

Table 4-2 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-2: Summary of the assumed timing for each component of Option 1A and Option 1B

Component	Expected timing (low)	Expected timing (central)
Option 1A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA • Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	N/A	2025/26
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 1B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2025/26
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	N/A	2029/30

Figure 5 below illustrates the type and location of the key elements for Option 1A and Option 1B.

Figure 5: Overview of the key elements in Option 1A and Option 1B

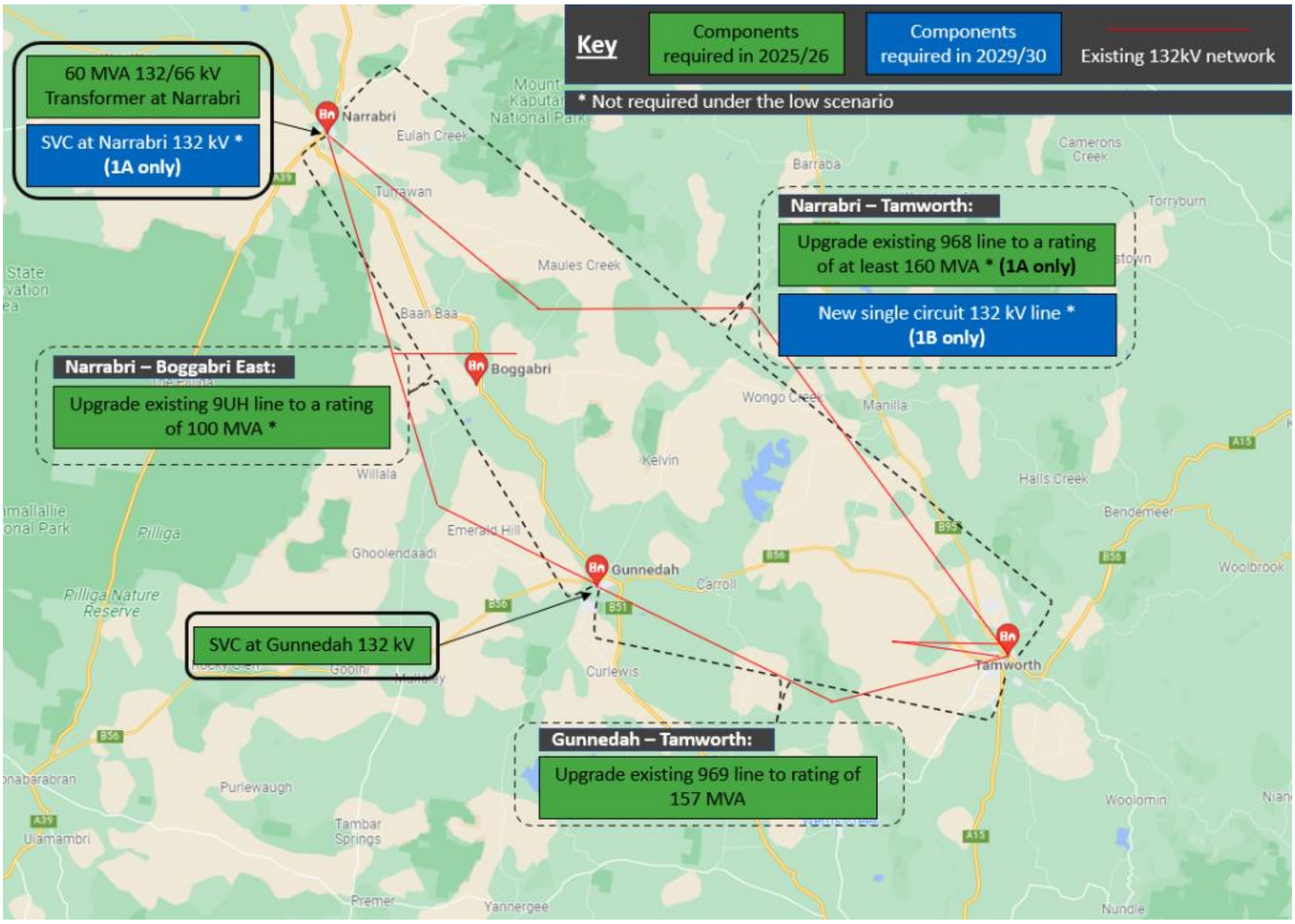


Table 4-3 summarises the expected construction time for each component.

Table 4-3: Summary of the expected construction time for each component of Option 1A and Option 1B

Component	Expected construction time[21]
Option 1A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA • Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	65 months
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	37 months

[21] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

Option 1B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	48 months
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	69 months

4.2. Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

This option involves installing new single or double circuit transmission lines between the Tamworth 330 kV substation and Gunnedah with the variants testing different line augmentations.

The scope of elements for Option 2A, Option 2B, Option 2C and Option 2D is shown in Table 4-1 above.

Table 4-4 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-4: Summary of the assumed timing for each component of Options 2A-2D

Component	Expected timing (low)	Expected timing (central)
Option 2A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah.	2025/26	2025/26
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	N/A	2025/26
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 2B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new double circuit 132 kV line between Tamworth 330 and Gunnedah, each circuit rated at 160 MVA • Decommission the existing 969 transmission line	2025/26	2025/26
• Upgrade the 9UH line to a rating of 100 MVA	N/A	2025/26
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	N/A	2029/30
Option 2C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah	2025/26	2025/26
• Upgrade the existing 969 line to a rating of 135 MVA	N/A	2025/26

• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30
Option 2D		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 330 kV line between Tamworth 330 and Gunnedah operated at 132 kV, rated at least 160 MVA	2025/26	2025/26
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	N/A	2025/26
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30

Figure 6 below illustrates the type and location of the key elements for Options 2A-2D.

Figure 6: Overview of the key elements in Options 2A-2D

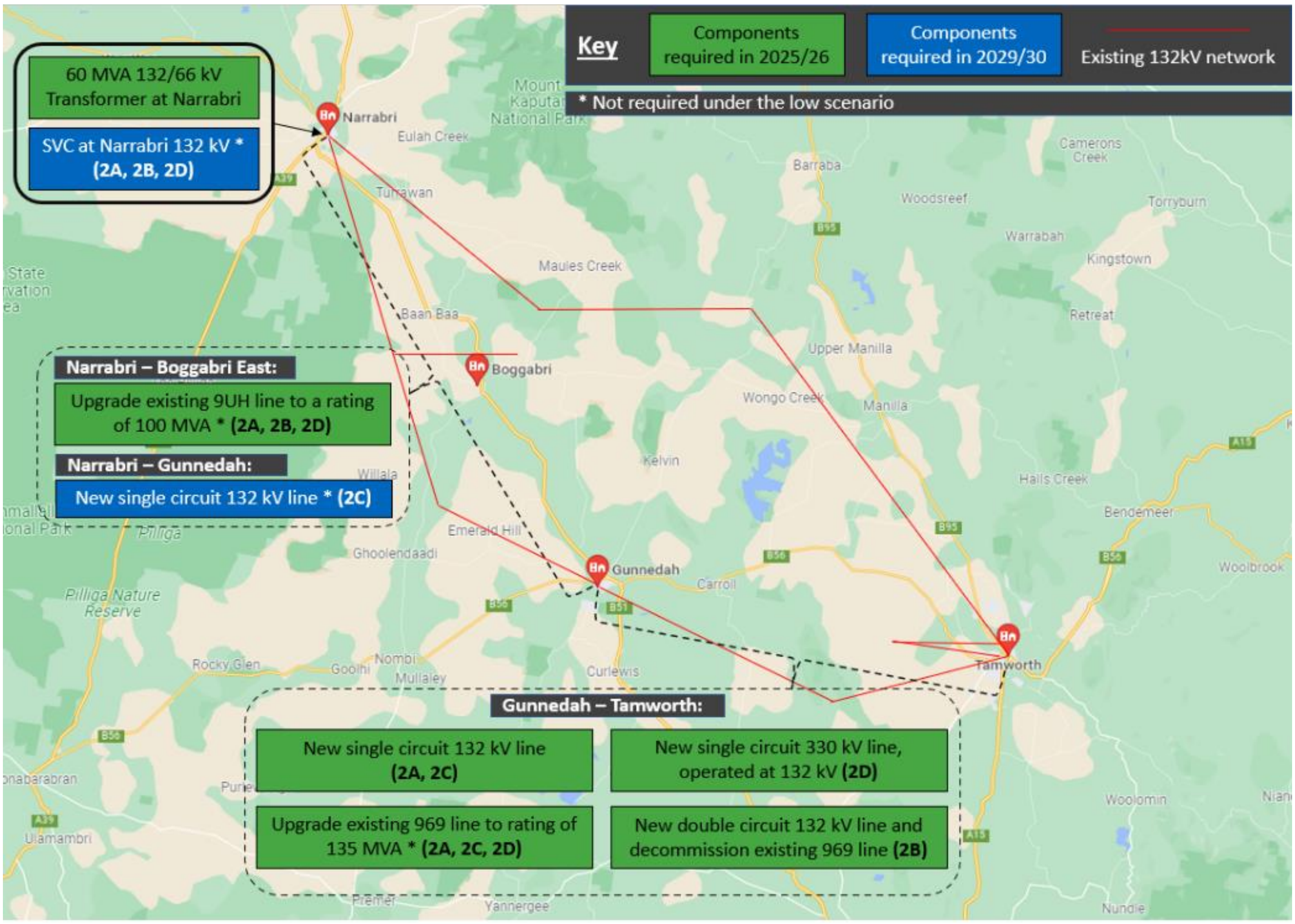


Table 4-5 summarises the expected construction time for each component.

Table 4-5: Summary of the expected construction time for each component of Options 2A-2D

Component	Expected construction time
Option 2A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri	62 months

• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah.	
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months
Option 2B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new double circuit 132 kV line between Tamworth 330 and Gunnedah, each circuit rated at 160 MVA • Decommission the existing 969 transmission line	64 months
• Upgrade the 9UH line to a rating of 100 MVA	57 months
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	37 months
Option 2C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 and Gunnedah	62 months
• Upgrade the existing 969 line to a rating of 135 MVA	57 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months
Option 2D	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 330 kV line between Tamworth 330 and Gunnedah operated at 132 kV, rated at least 160 MVA	61 months
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months

4.3. Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

This option involves rebuilding line 969 to be a double circuit line with the three variants testing different line augmentations and dynamic reactive support levels.

The scope of the elements for Option 3A, Option 3B and Option 3C is shown in Table 4-1 above.

Table 4-6 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-6: Summary of the assumed timing for each component of Options 3A-3C

Component	Expected timing (low)	Expected timing (central)
Option 3A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26

• Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit		
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2025/26
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	N/A	2029/30
Option 3B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2025/26
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	N/A	2029/30
Option 3C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit	2025/26	2025/26
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30

Figure 7 below illustrates the type and location of the key elements for Options 3A-3C.

Figure 7: Overview of the key elements in Options 3A-3C

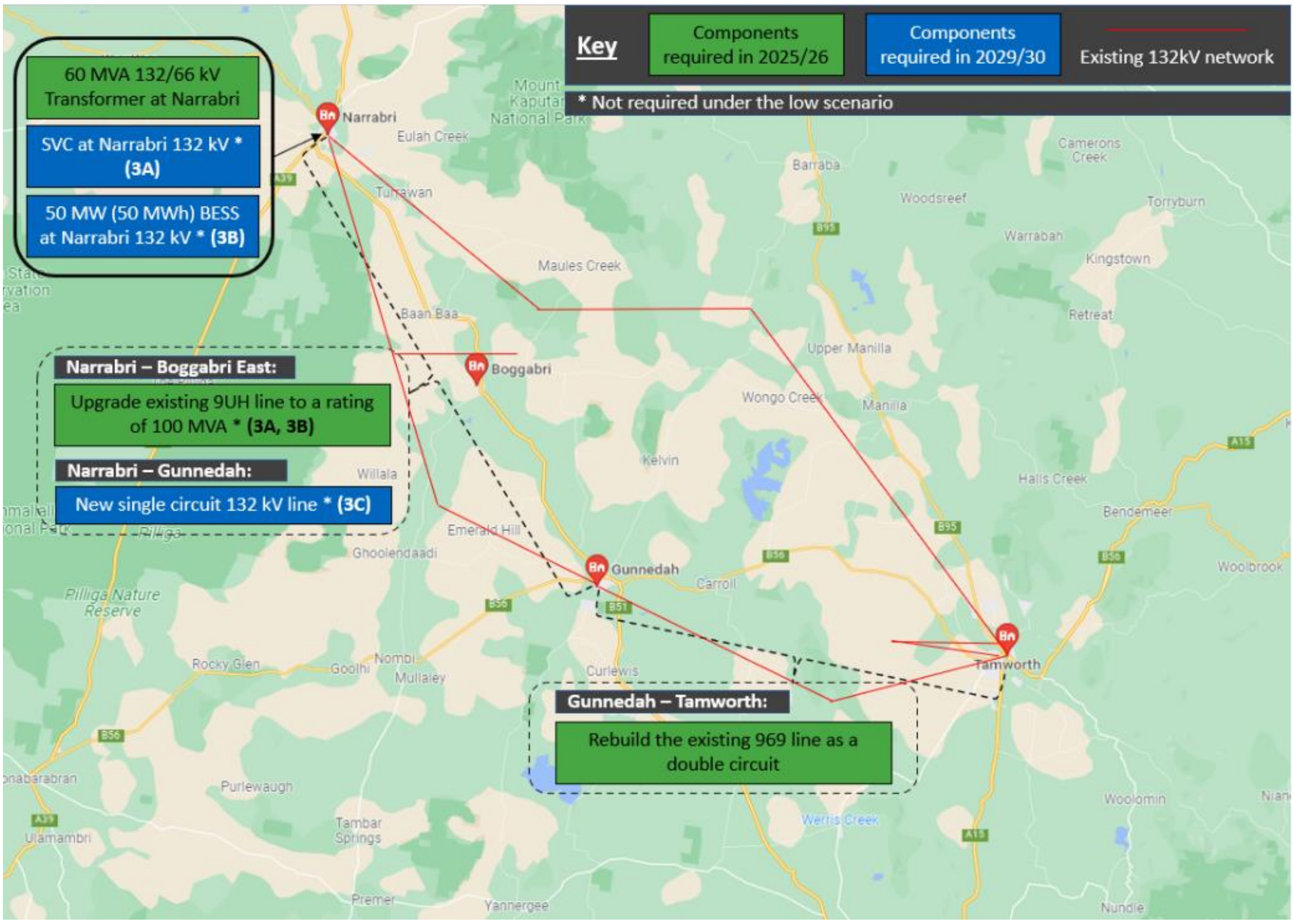


Table 4-7 summarises the expected construction time for each component.

Table 4-7: Summary of the expected construction time for each component of Options 3A-3C

Component	Expected construction time[22]
Option 3A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit	44 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	37 months
Option 3B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	44 months

[22] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

• Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit	
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	39 months
Option 3C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 and Gunnedah Substations as a double circuit	44 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months

4.4. Option 5 – Non-network options

The two non-network options, Option 5A and Option 5B, use BESS to provide a network support service. Option 5A and Option 5B vary by the size, number and location of the BESS. The details of these options has not been presented in this PADR to preserve the requested confidentiality by proponents.

We have not exhaustively tested and confirmed the technical feasibility of the non-network elements put forward in response to the PSCR as part of this PADR. Doing so would require requesting additional information and modelling from the third party proponents and we note the costs and effort involved in providing this material, as well as a general desire from submitters to first understand whether their proposal is likely to be in the running for identification as part of the preferred option. We have consequently assumed that each non-network solution assessed is technically feasible for the purposes of the PADR and intend to undertake a full assessment of technical feasibility as part of the PACR.

The non-network solutions are not considered to be long-term standalone solutions and, instead, defer or avoid the rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North, as part of the preferred network option at this stage of the RIT-T (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to address the IPART reliability standard for the Narrabri area.

Table 4-8 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-8: Summary of the assumed timing for each component of Option 5A and Option 5B

Component	Expected timing (low)	Expected timing (central)
Option 5A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah or Narrabri 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	N/A	2029/30

• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30
Option 5B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30

4.5. Options considered but not progressed

We have also considered whether other options could meet the identified need. The reasons these options were not progressed are summarised in Table 4-9.

Table 4-9: Options considered but not progressed

Option	Reason(s) for not progressing
Capacitor banks/ switched capacitors	Not technically feasible. Our studies show that due to the expected extensive load growth in the Narrabri and Gunnedah areas, adding a number of additional capacitor banks or switched capacitors in the area is a non-credible solution since step changes in voltages caused by their switching would lead to voltage excursions outside NER requirements. This remains unchanged since the PSCR.
Connection to the New England Transmission Infrastructure (NETI) project	This option was presented in the PSCR and involves connecting to a potential new non-prescribed project in the Gunnedah area called the NETI (a potential 330 kV transmission line between Tamworth 330/132 kV substation and a new 330 kV substation between Tamworth and Gunnedah with the aim of unlocking new renewable energy investment in the New England area of NSW). While ARENA has provided funding to Transgrid to assess the feasibility of an innovative commercial model to develop the NETI,[23] we have removed the option of connecting to the potential NETI from the PADR assessment given the uncertainty involved (particularly around the timing). We consider this option not technically feasible at this stage of the RIT-T but may revisit it as part of the PACR (particularly if a connection enquiry is made).

[23] https://arena.gov.au/projects/transgrid-new-england-renewable-energy-zone/

5. Ensuring the robustness of the analysis

The investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of reasonable scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three 'reasonable 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.[24] 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 assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound, conservative estimate of the present value of net economic benefits;
- a 'central' scenario based on a central set of variable estimates and reflects the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions selected to investigate an upper bound of net economic benefits

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

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24 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, *RIT-T Application Guidelines*, December 2018, p. 42.

Table 5-1: Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast (as outlined in section 2.2)	Low demand forecast (as outlined in section 2.2)	Central demand forecast (as outlined in section 2.2)
New renewable generation in the area	In-service and committed generators from Appendix B.	All in-service, committed and advanced generators from Appendix B.	In-service and committed generators from Appendix B.
Wholesale market benefits estimated	Estimated based on 'progressive change' 2022 ISP scenario (as outlined in section 6.3 below)	30 per cent lower than central scenario estimate	30 per cent higher than central scenario estimate
VCR	$46.93/kWh	$32.85/kWh	$61.01/kWh
Discount rate	5.50%	7.50%	2.23%

5.2. Weighting the reasonable scenarios

We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

5.3. Sensitivity 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 range of factors tested as part of the sensitivity analysis in this PADR are:

- the assumed timing of both the network and non-network components;
- the central scenario but adopting the low demand forecast;
- lower assumed future reinvestment costs for batteries;
- different network capital costs for the credible options; and
- alternate commercial discount rate assumptions.

The results of the sensitivity tests are discussed in section 7.5.

In addition, as part of the analysis we have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for key variables beyond which the outcome of the analysis would change.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

6. Estimating the market benefits

As outlined in section 2, the key benefit expected from the options is avoided involuntary load shedding in the North West Slopes area. In addition, for the two options that involve a non-network component, there are also expected to be benefits from anticipated changes in the wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the National Electricity Market (NEM) outcomes expected in each case, and includes the location and quantity of load in North West Slopes, as well as the type, quantity and timing of future generation investment.

This section outlines how each of the broad categories of market benefit have been estimated.

EY has undertaken the wholesale market modelling component of the PADR assessment. Appendix D provides additional detail on the wholesale market modelling undertaken by EY. We are also publishing a separate modelling report prepared by EY alongside this PADR that provides greater detail on the modelling approach and assumptions, to provide transparency to market participants.

6.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PADR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken.

Under the base case, where the longer-term constraints associated with load growth in the North West Slopes area is unresolved, significant interruption of supply to loads in the area under normal and contingency conditions would be expected, due to voltage limitations and/or voltage collapse in the local supply network.

While this is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the assessment is required to use this base case as a common point of reference when estimating the net benefits of each credible option.

We have not quantified the avoided expected involuntary load shedding after 2028/29 as part of the PADR analysis since each option will address all constraints equally from then and avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2028/29 will therefore not assist in identifying the preferred option under the RIT-T. Moreover, the levels of unserved energy under the base case are expected to be extremely high and so will dwarf the other quantified costs and benefits if this approach is not applied (e.g., we estimate that these will exceed $600 million/year by 2029/30 under the central demand forecasts and increase thereafter).

Importantly, we have taken into account all avoided expected involuntary load shedding for the years in which the options differ in respect of how much involuntary load shedding will occur, ie, prior to 2028/29. This captures the *differences* in the expected avoided involuntary shedding *between* options as well providing an indication of the extent of these benefits overall.

We consider this is consistent with the approach adopted in other RITs, the Energy Networks Australia RIT-T Handbook[25] and advice provided to the AER.[26]

6.2. Avoided involuntary load shedding in the North West Slopes area

We have run system studies to estimate the Expected Unserved Energy (EUE) in the North West Slopes area under each of the base cases and each of the credible options.

The avoided EUE for each option has been valued using the estimated VCRs published by the AER.[27] Specifically, we have developed a load-weighted VCR estimate for the central scenario using the AER VCR values for the customer groups relevant to the region. We have then applied VCR estimates that are 30 per cent lower and 30 per cent higher for the low and high scenarios, respectively, consistent with the AER's specified +/- 30 per cent confidence interval.[28]

The EY market modelling has also quantified the impact of changes in involuntary load shedding *outside* of the North West Slopes area associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of EUE in each hourly trading interval over the modelling period, and then applies the AER VCRs to quantify the estimated value of avoided EUE outside of the North West Slopes area for each option. However, these estimated changes in EUE are not expected to be material for any of the credible options.

6.3. Options replacing line 969 would avoid future wood pole replacement costs

Under the base case, we expect to replace aged wood pole structures on line 969 within the next twenty years. The expected timing of this work has been updated since the PSCR (from 'the next five to ten years') in light of our latest asset condition monitoring.

For all options that replace line 969 with a new line (i.e., Option 2B, Option 3A, Option 3B, Option 3C, Option 5A and Option 5B), this expenditure is able to be avoided and so provides an economic benefit in the analysis. However, given the majority of the expenditure is expected in the last few years of the assessment period, it is found to be a minor source of benefit for these options.

6.4. Wholesale market benefits

As outlined in section 2.3, two of the credible options assessed in this PADR involve the use of BESS and are able to use a portion of their capacity to dispatch to the wholesale market. Dispatching to the wider market can offset more costly generation that would otherwise operate in the NEM and thus provide wider wholesale market benefits on top of the avoided unserved energy that all options provide.[29]

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. For the purposes of the PADR assessment we have made a key assumption, which is favourable to these options, that these components are able to use their *entire* capacity to dispatch in the NEM (when, in reality, only a portion would be able to be offered inti the NEM as some BESS capacity would need to be reserved to

[25] ENA, *RIT-T Economic Assessment Handbook for non-ISP RIT-Ts*, Version 2.0, 26 October 2020, p. 51.
[26] Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.
[27] The VCR values have been taken from the most recent VCR update from the AER, i.e.: AER, *Annual update – VCR review final decision – Appendices A – E*, December 2021.
[28] AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.
[29] While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options, as outlined in section 2.3.

provide network support). We will be working with proponents to revise this assumption ahead of the PACR.

The relevant credible options have been assessed using a set of market modelling assumptions based on the 'progressive change' scenario identified and consulted on by AEMO to be used in the 2022 ISP. We consider focussing on a single ISP scenario to be a proportionate approach since our results indicate that the wholesale market benefits do not have a bearing on the identification of the preferred option, with the ranking instead being driven by the timing, and so avoided unserved energy, differences across the options, as outlined in section 7 below.

AEMO has assigned the 'progressive scenario' a 29 per cent weighting in its draft 2022 ISP, released on 10 December 2021. This is slightly below the 'step change' scenario, to which AEMO has assigned a 50 per cent weighting and which it notes is considered by energy industry stakeholders to be the most likely scenario to play out.[30] We intend to update the market modelling in the PACR to be based on the step change scenario (despite the PADR modelling finding that the estimated market benefits are not material to the outcome).[31]

While the EY market modelling for this RIT-T focusses on the progressive change ISP scenario, we have also applied a broad assumption of 30 per cent lower and 30 per cent higher aggregate wholesale market benefits as part of the low and high scenario investigated, respectively. This 30 per cent does not represent any sort of confidence level for the market modelling conducted by EY but, instead, has been instigated by us as a proportionate approach to further test the robustness of the preferred option.

Appendix D summarises the key variables under the progressive change scenario that influence the wholesale market benefits of the options. Additional detail on the wholesale market modelling undertaken, including the assumptions and methodologies, can be found in the accompanying EY market modelling report.

Table 6-1 below summarises the specific categories of wholesale market benefit under the RIT-T that have been modelled as part of this PADR.

Table 6-1: Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PADR

Market benefit	Overview
Changes in costs for other parties in the NEM	This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. The capital and operating costs associated with the BESS components have been captured in the PADR assessment as a cost to other parties, reflecting that this is an additional resource cost to the NEM that would not be incurred if we did not sign a network support agreement with the proponents for these options (as these projects are not already committed or anticipated). This is consistent with the AER's revised guidance on the treatment of NNO.[32]

[30] AEMO, *Draft 2022 Integrated System Plan*, December 2021, pp. 25-26 & 29.
[31] We initially modelled the market benefits for this PADR using AEMO's 'steady progress' 2022 ISP scenario, which AEMO noted in the 2021 Inputs, Assumptions and Scenarios Report (IASR) is 'similar conceptually to the 2020 central scenario'. However, the draft 2022 ISP released on 10 December 2021 stated that the steady progress scenario is no longer relevant, given Australia's commitment to net zero emissions by 2050. We therefore updated the market modelling for this RIT-T over December 2021 and January 2022 to be based on the progressive change scenario (time would not permit updating to the step change scenario).
[32] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

Market benefit	Overview
	However, the market benefits associated with these options operating outside of times needed for network support (in particular their impact on dispatch costs and generation investment), compared with the base case in which those batteries are not in place, has also been captured as part of the modelling for each of these options.
Changes in fuel consumption in the NEM	This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case. Where non-network options are able to trade in the wholesale market outside of their network support commitments, this may result in a different pattern of generation dispatch.
Changes in network losses	The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario. The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding. The reduction in network losses between the base case and the options is considered immaterial for the options considered in this PADR but reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.
Differences in unrelated transmission costs	This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZ that could be avoided if a credible option is pursued. AEMO has identified a number of REZ in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZ. While the credible options being considered in this RIT-T can in theory assist with allowing the development of some of these REZ without the need for additional intra-regional transmission investment (or with less of it), it is in a very minor way and this category of market benefit is not considered significant for this RIT-T.
Changes in involuntary load curtailment (outside of the North West Slopes area)	This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each relevant credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted the AER VCRs to quantify the estimated value of avoided EUE for the purposes of this assessment. This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding outside of the North West Slopes area between each option and the base case.
Changes in voluntary load curtailment	Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching

Market benefit	Overview
	higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment. This class of market benefit has been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment is not significantly different between the option cases and the base case.

6.5. General modelling parameters adopted

The RIT-T analysis spans a 20-year assessment period from 2021/22 to 2040/41.[33]

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes 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 are 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 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with the assumptions adopted in 2021 Inputs, Assumptions and Scenarios (IASR). The RIT-T also 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 2.23 per cent,[34] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[35]).

6.6. Classes of market benefit not considered material

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.[36]

Competition benefits have not been estimated for any of the options since they are not considered material in the context of this RIT-T. This RIT-T is focussed on efficiently meeting the required reliability standards in the North West Slopes area and, while some options are expected to generate a level of wholesale market benefits, it is not considered sufficient to affect the competitiveness of generator bidding behaviour in any region of the NEM.

Option value is likely to arise in a RIT-T assessment where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered are sufficiently flexible to respond to that change. The credible options outlined in this PADR exhibit flexibility in terms of how they can be developed and we have captured the option value of this flexibility implicitly

[33] This has been updated since the PSCR (which stated a 20 year assessment period would be used) as market modelling was not contemplated at the time of the PSCR.
[34] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/directlink-determination-2020-25
[35] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.
[36] NER clause 5.16.1(c)(6).

through their components having different assumed timings across the scenarios. We consider this consistent with the AER guidance on the treatment of option value and consider that a wider option value modelling exercise would be disproportionate to any option value that may be identified for this specific RIT-T assessment.

7. Net present value results

This section outlines the results of the assessment we have undertaken of the credible options.

Due to the confidentiality requested by the proponents of the non-network solutions, we are only able to present the overall *net* market benefits of Option 5A and 5B (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The accompanying market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option modelled. Neither this PADR nor the accompanying market modelling report provide the estimated wholesale market benefits of the non-network options in dollar terms, in order to protect the confidentiality of the options assessed.

All figures of the same type in this section have been presented on the same scale (unless otherwise stated) in order to highlight the differences across scenarios.

7.1. Central scenario

The central scenario reflects our central view of key underlying assumptions and is considered the most likely scenario in terms of the net market benefits for each of the options. These assumptions include central demand forecasts, network cost estimates, VCR and commercial discount rate estimates. This scenario also includes EY's market modelling of the wholesale market benefits for the non-network options based on the 'progressive change' scenario to be used in the 2022 ISP.

Under these assumptions, the options involving non-network solutions in the short-term (i.e., Option 5A and Option 5B) are preferred over the solely network options. This is primarily due to these options being able to be commissioned approximately one to three years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately 6 per cent greater than Option 5A and 29 per cent greater than Option 3A.

Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, under this scenario, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[37]

Figure 7-1 shows the overall estimated net benefit for each option under the central scenario. All figures of this format in the PADR show the top-ranked option in green, and the other options in blue.

[37] The present value of all capex and opex of Option 3A under this scenario is $114 million, which compares to $100 million for Option 2B.

Figure 7-1: Summary of the estimated net benefits under the central scenario

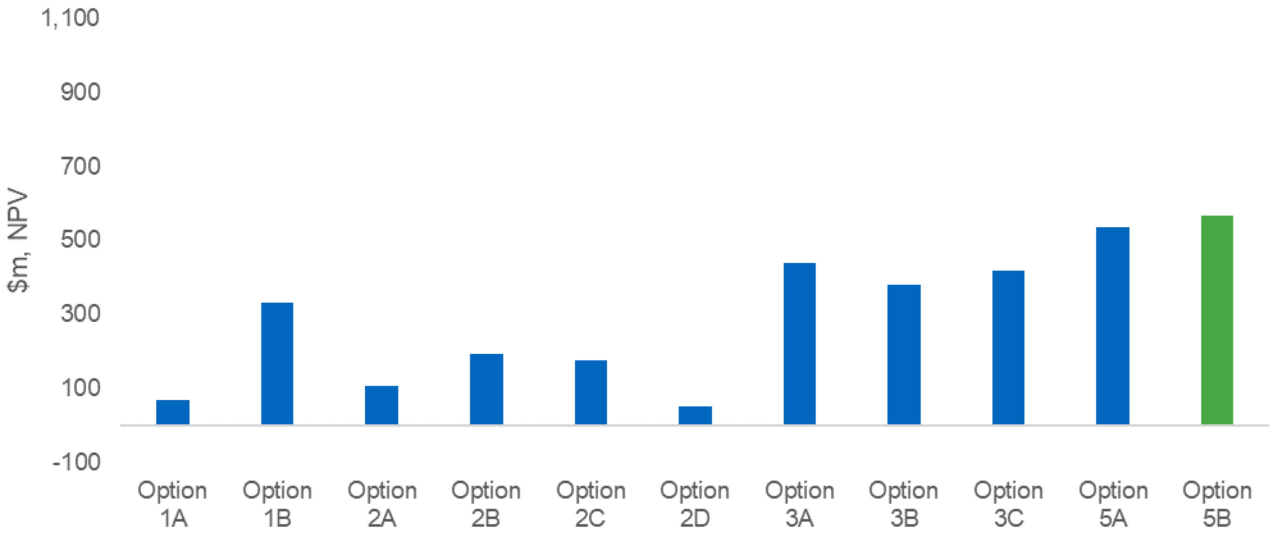
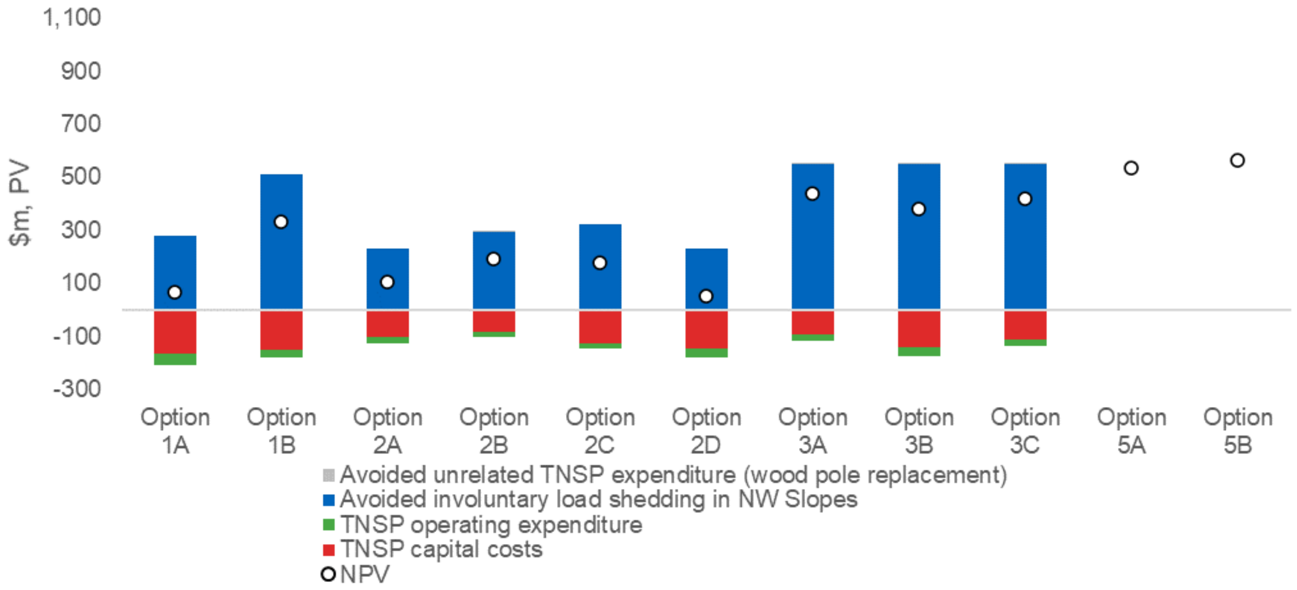


Figure 7-2 shows the composition of estimated net benefits for each option under the central scenario. Only the net numbers are shown for Option 5A and 5B in order to protect the confidentiality of these options.

Figure 7-2: Breakdown of estimated net benefits under the central scenario



The wholesale market modelling for the non-network options finds that the primary sources of benefit are from avoided and deferred capex for new generation/storage and avoided fuel cost savings. However, the wholesale market benefits are found to not be material overall in the assessment, making up approximately 10 per cent of the total estimated gross benefit for both of these options, and do not affect the ranking of the options, i.e., if these sources of market benefits were removed from the analysis, Option 5B would remain the top-ranked option.

7.2. Low net economic benefits

The low net economic benefits scenario reflects a number of assumptions that give a lower bound and conservative estimate of net present value of net economic benefits. These assumptions include the low demand forecast, high network cost estimates, low VCR and a high commercial discount rate estimate. This scenario also includes 30 per cent lower wholesale market benefits than those estimated by EY as an additional robustness test for the option rankings.

Under these assumptions, Option 5B remains the preferred option with estimated net benefits of $19 million, materially ahead of Option 1A and Option 1B, which both have estimated net benefits of approximately $10 million.

All other options besides Option 5A are found to have net costs, meaning that they are not preferred over the base case 'do nothing' option, which is driven by the significantly lower avoided unserved energy under this scenario compared to the central scenario. However, we note that all net costs are only marginal and, if we did not apply the approach to removing unserved energy that has no bearing on the ranking of the options (outlined in section 6.1), all options would be found to have positive net benefits.

Figure 7-3 shows the overall estimated net benefit for each option under the low economic benefits scenario.

Figure 7-3: Summary of the estimated net benefits under the low economic benefits scenario

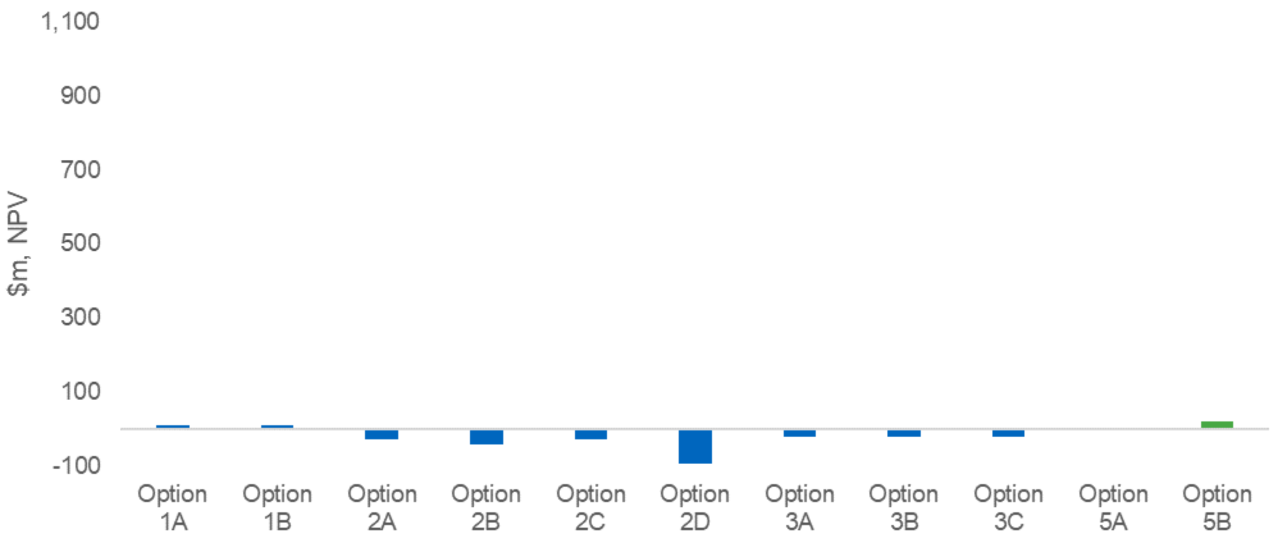
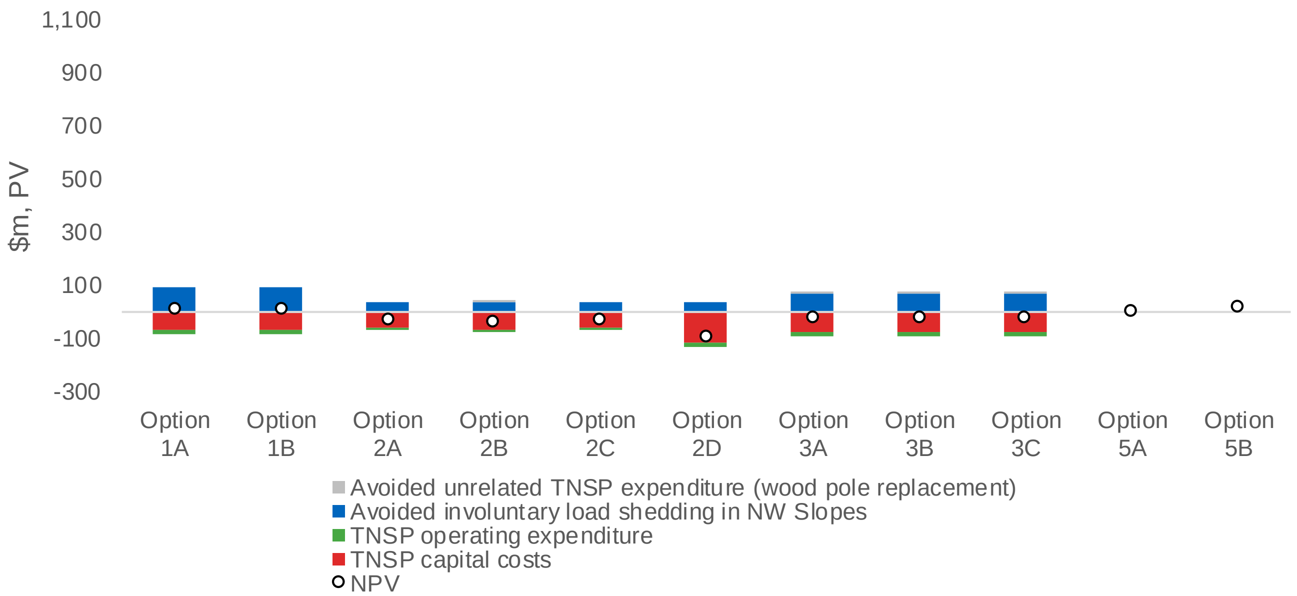


Figure 7-4 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A and Option 5B to protect the confidentiality of these options.

Transgrid

Figure 7-4: Breakdown of estimated net benefits under the low economic benefits scenario



In contrast to the central scenario, the wholesale market benefits make up between 32 and 35 per cent of the total estimated gross benefit for Option 5A and Option 5B under the low scenario. Further, the wholesale market benefits do affect the ranking of the options and, if these sources of market benefits were removed from the analysis, Option 1A and Option 1B would become the preferred options under the low scenario.

7.3. High net economic benefits

The high net economic benefits scenario reflects assumptions that give an upper bound estimate of net present value of net economic benefits. These include the central demand forecast (as outlined in section 2.2), low network cost estimates, high VCR and a low commercial discount rate estimate. This scenario also includes 30 per cent higher wholesale market benefits than those estimated by EY as an additional robustness test for the option rankings.

Under these assumptions, as with the central scenario, the options involving non-network solutions in the short-term (i.e., Option 5A and Option 5B) are preferred over the solely network options. This is again due to these options being able to be commissioned approximately one to three years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately 5 per cent greater than Option 5A and 28 per cent greater than Option 3A.

As with the central scenario, Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, under this scenario, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[38]

[38] The present value of all capex and opex of Option 3A under this scenario is $83 million, which compares to $72 million for Option 2B.

Figure 7-5 shows the overall estimated net benefit for each option under the high economic benefits scenario.

Figure 7-5: Summary of the estimated net benefits under the high economic benefits scenario

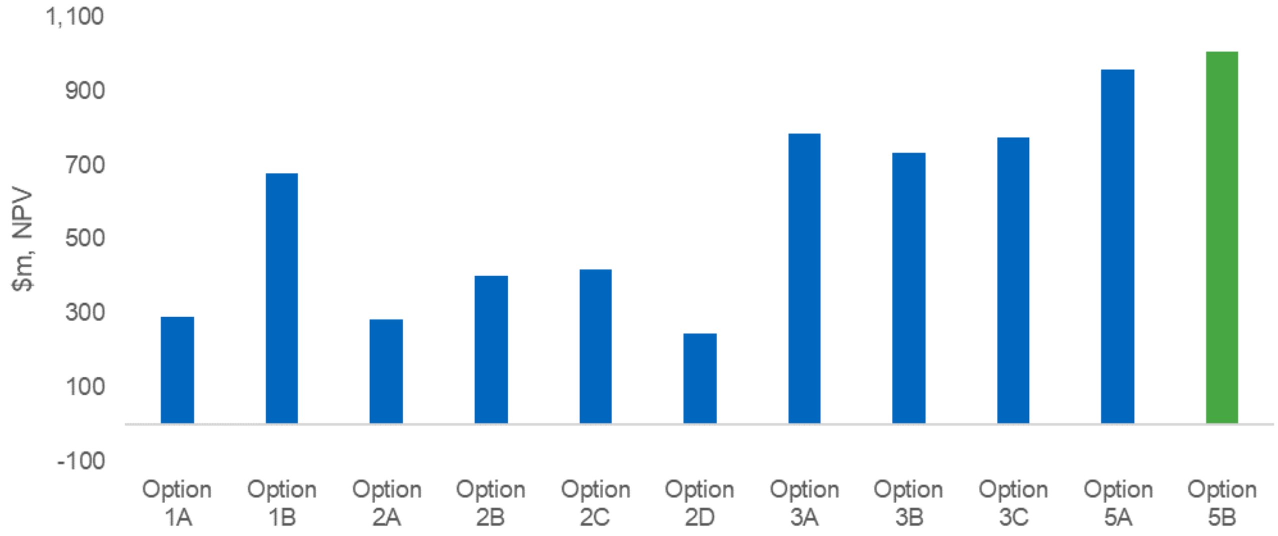
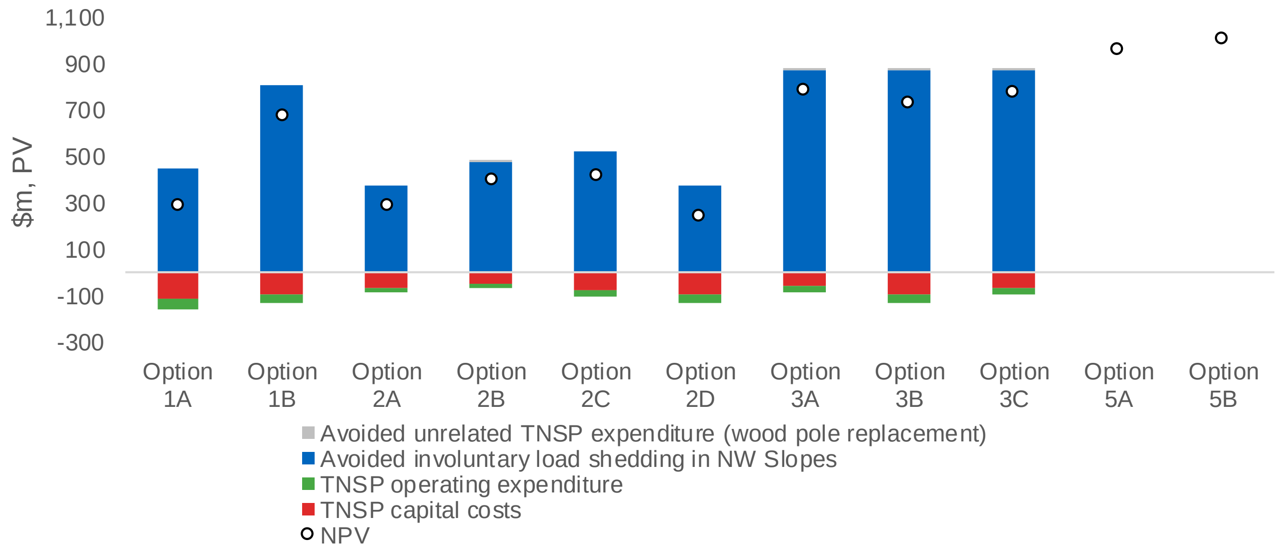


Figure 7-6 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A and Option 5B in order to protect the confidentiality of these options.

Figure 7-6: Breakdown of estimated net benefits under the high economic benefits scenario



As with the central scenario, the wholesale market benefits are found to not be material overall in the assessment for this scenario, making up between 11 and 12 per cent of the total estimated gross benefit for Option 5A and Option 5B, and do not affect the ranking of the options, i.e., if these sources of market benefits were removed from the analysis, Option 5B would remain the top-ranked.

7.4. Weighted net benefits

Figure 7-7 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above).

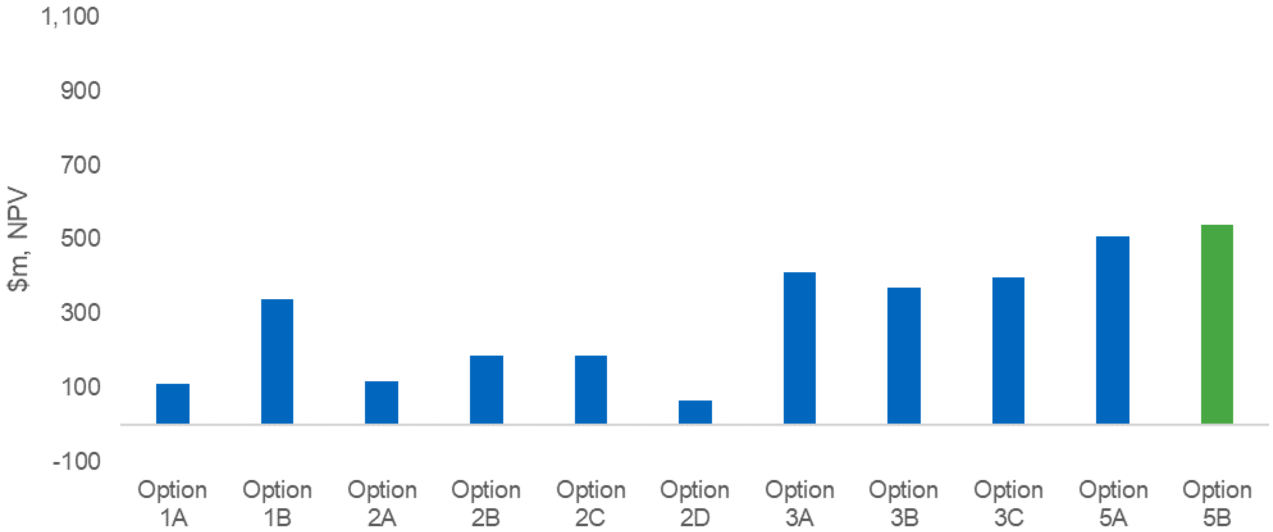
We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

Under the weighted outcome, the options involving non-network solutions in the short-term (i.e., Option 5A and Option 5B) are preferred over the solely network options.

Option 5B is the top-ranked option overall, with net benefits that are approximately 6 per cent greater than the second ranked option (Option 5A) and 32 per cent greater than the top-ranked solely network option (Option 3A).

While Option 3A has the second lowest expected total cost of the solely network options, in present value terms, under this scenario, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[39] Option 3A is therefore considered the preferred network option at this stage of the RIT-T and is the network option the non-network options have been coupled with.

Figure 7-7: Summary of the estimated net benefits, weighted across the three scenarios



A key determinant of the overall preferred option is the assumed build times, and ultimate commissioning dates, of each of the credible options since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided. This is investigated further in section 7.5.1 below.

[39] The present value of all capex and opex of Option 3A under this scenario is $101 million, which compares to $87 million for Option 2B.

7.5. Sensitivity 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 range of factors tested as part of the sensitivity analysis in this PADR are:

- the assumed timing of both the network and non-network components;
- the central scenario but adopting the low demand forecast;
- lower assumed future reinvestment costs for batteries;
- different network capital costs of the credible options; and
- alternate commercial discount rate assumptions.

Each of the sensitivity tests undertaken in this PADR are discussed in the sections below.

We note that the scale in some of the figures in this section is smaller than their counterparts in earlier sections in order to show the impact of these sensitivities more clearly.

7.5.1. Assumed timing of the network and non-network components

As outlined in section 7.4, the key determinant of the overall preferred option in this RIT-T assessment is the assumed build times, and ultimate commissioning dates, of each of the credible options since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided.

While the commissioning dates for each option have been estimated using our, and third party (where relevant), best endeavours at this point in time, we have also investigated a range of sensitivities that relax these assumptions to see how the overall conclusion of the assessment is affected.

The two tables below investigate the effects of assuming earlier commissioning dates for the top-ranked solely network option (Option 3A) as well as assuming later commissioning dates for the top-ranked option involving non-network components (Option 5B). Specifically, Table 7-1 shows the difference in dollars between Option 5B and Option 3A under various alternate timing assumptions, while Table 7-2 shows the estimated net benefits of Option 5B as a percentage of the estimated net benefits of Option 3A under the various alternate timing assumptions.

Table 7-1: Difference between Option 5B and Option 3A under timing sensitivities ($m, NPV), weighted

	Option 5B - no change	Option 5B - 1 year delay	Option 5B - 2 year delay
Option 3A - no change	129.7	123.6	-13.1
Option 3A - 1 year forward	24.6	18.5	-118.2
Option 3A - 2 years forward	21.5	15.4	-121.3

Black text shows where Option 5B is preferred, while red text indicates where Option 3A is preferred.

Table 7-2: Estimated net benefits of Option 5B as a percentage of the estimated net benefits of Option 3A under timing sensitivities (%), weighted

	Option 5B - no change	Option 5B - 1 year delay	Option 5B - 2 year delay
Option 3A - no change	131.6%	130.1%	96.8%
Option 3A - 1 year forward	104.8%	103.6%	77.1%
Option 3A - 2 years forward	104.1%	103.0%	76.6%

Black text shows where Option 5B is preferred, while red text indicates where Option 3A is preferred.

The two tables above show that the results of the analysis are relatively sensitive to the assumed commissioning dates for these two options. Specifically, all alternate assumed commissioning date combinations above result in the estimated net benefits of Option 5B being either within 5 per cent of those for Option 3A, or Option 3A becoming preferred option (the one exception to this is when there is assumed to be no change in the timing of Option 3A and a one year delay to Option 5B, which results in Option 5B having approximately 30 per cent greater net benefits than Option 3A), e.g., if Option 3A was to be delivered a year earlier and Option 5B remained on the same timing, then Option 3A would have almost the same benefit as Option 5B.

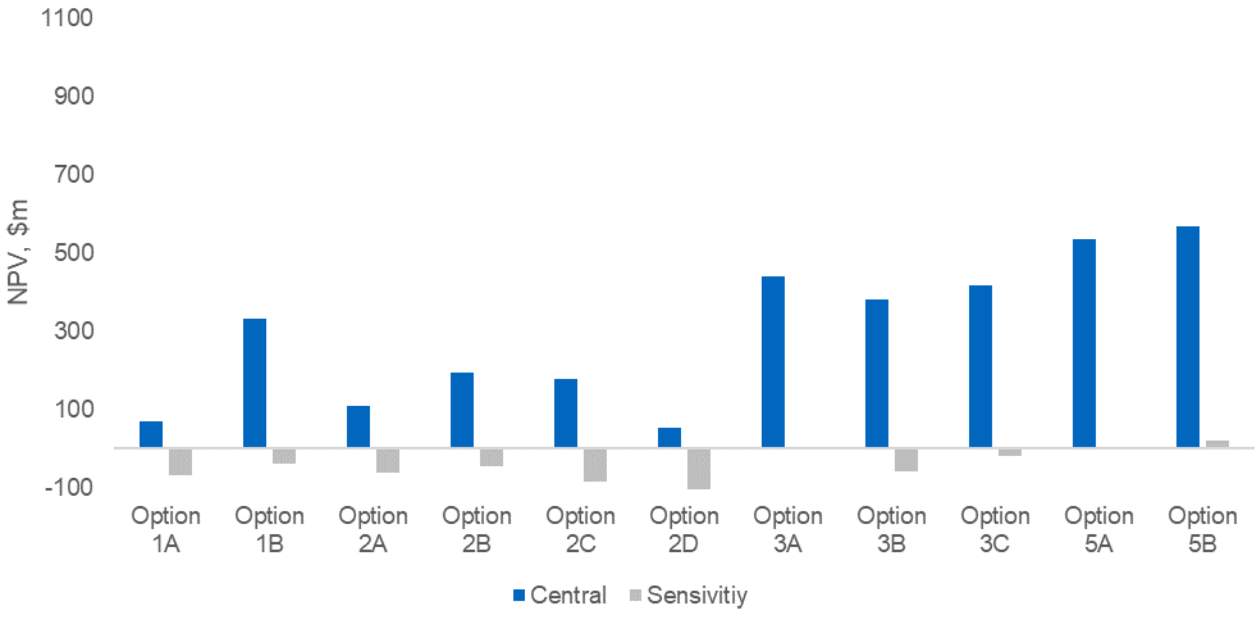
While the above sensitivities are focused in particular on the rankings between the network and non-network options (rather than between the non-network options), we note that the assumed timings are also likely to be a key driver of the rankings between the non-network options.

7.5.2. Central scenario but assuming the low demand forecast

Figure 7-8 shows the effect of assuming the low demand forecasts for the central scenario. Specifically, it keeps all assumptions under the central scenario the same with the exception of the demand forecast (where the low forecast is used).

Under these assumptions, all options other than the preferred option (Option 5B), Option 5A and Option 3A are found to have net costs. While this illustrates how significant the assumed spot loads are to the level of net benefits expected (e.g., the estimated net benefits of Option 5B fall from $567 million to $22 million under this sensitivity), we note that, as with the core low scenario, all options would have positive net benefits if the full amount of unserved energy was captured in this sensitivity. Moreover, we note that the preferred option for a reliability corrective action is able to have negative net benefits under the RIT-T.

Figure 7-8: Impact of assuming the low demand forecast in the central scenario

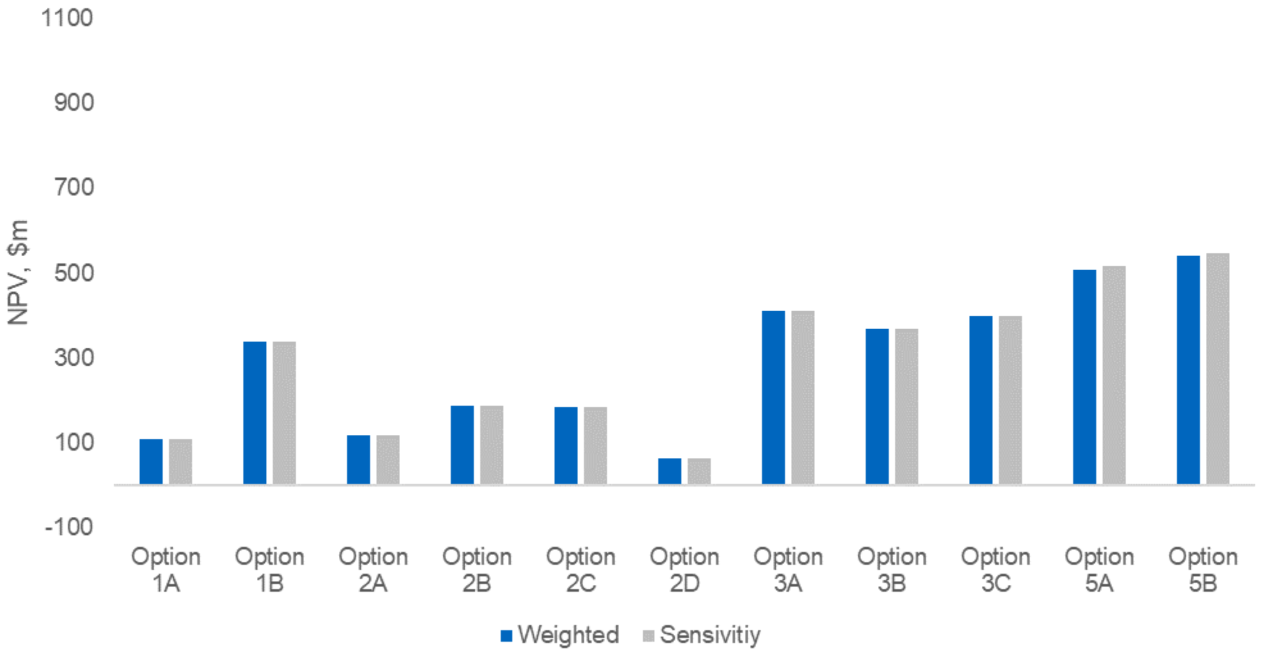


7.5.3. Lower assumed reinvestment cost for batteries

The modelling assumes that batteries are reinvested in over the assessment period, since their asset lives are shorter than the assessment period. The core analysis assumes that this re-investment occurs at the same real cost as the initial investment. This sensitivity tests the effect of assuming a lower real reinvestment cost in light of these costs likely decreasing going forward as technologies mature.

Figure 7-9 shows the effect of assuming an indicative 25 per cent real cost reduction for battery reinvestment. It shows that the core results are not sensitive to the assumed reinvestment cost for batteries, which reflects how far into the future this reinvestment occurs.

Figure 7-9: Impact of assuming 25 per cent lower reinvestment battery costs, weighted scenario

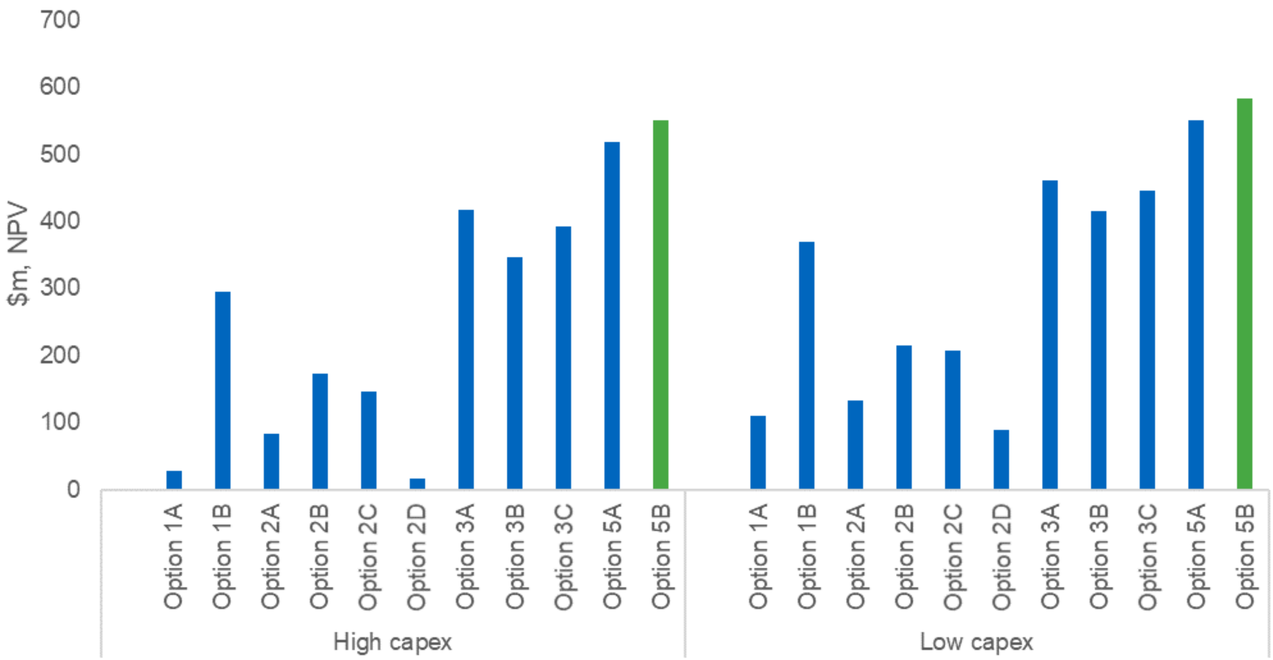


7.5.4. Network capital costs of the credible options

We have tested the sensitivity of the results to changes in the underlying network capital costs of the credible options.

Figure 7-10 shows both 25 per cent higher and 25 per cent lower assumed capital costs.

Figure 7-10: Impact of 25 per cent higher and lower network capital costs, central scenario



Neither sensitivity changes the finding that the non-network options are preferred over the network options, and that Option 5B is the top-ranked option. In addition, neither sensitivity changes the finding that Option 3A is the preferred network option.

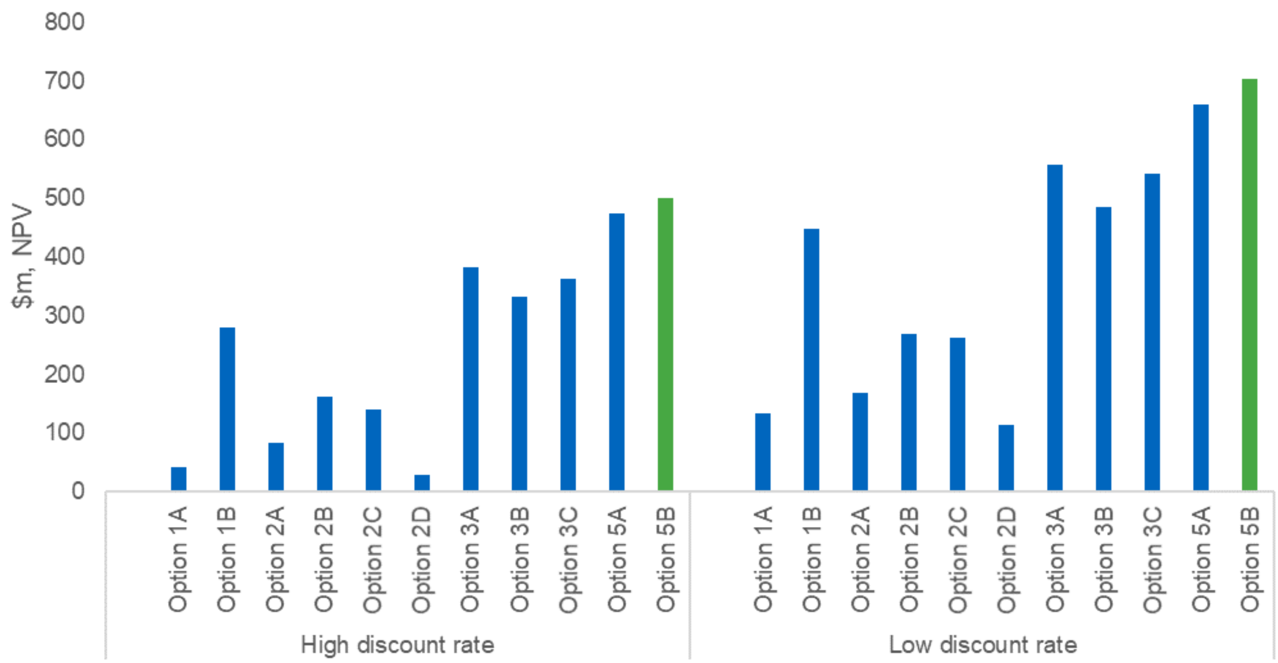
We further find that even if network costs (including the network cost elements of the non-network options) were assumed to be zero, Option 5B would still be preferred over Option 3A on account of the additional unserved energy it avoids.

7.5.5. Commercial discount rate assumptions

Figure 7-11 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment on a weighted basis. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 7.50 per cent; and
- a low discount rate of 2.23 per cent.

Figure 7-11: Impact of different assumed discount rates, central scenario



Neither sensitivity changes the finding that the non-network options are preferred over the network options, and that Option 5B is the top-ranked option. In addition, neither sensitivity changes the finding that Option 3A is the preferred network option.

We further find that there is no realistic discount rate that would result in Option 3A being preferred over Option 5B.

8. Conclusion

The results of the PADR assessment find that the options involving non-network solutions in the short-term (i.e., Option 5A and 5B) are preferred over the solely network options. The options involving non-network solutions in the short-term are found to deliver estimated net benefits of approximately $507 million to $540 million overall relative to the base case 'do nothing' option on a weighted basis, which compares to $410 million for the top-ranked solely network option (Option 3A).

Option 5B is the top-ranked option on a weighted basis, with net benefits that are approximately 6 per cent greater than the second ranked option (Option 5A) and 32 per cent greater than the top-ranked solely network option (Option 3A), as well as in each of the three scenarios investigated.

At this stage of the RIT-T, the preferred option is therefore Option 5B. We consider Option 5B satisfies the RIT-T at this draft stage and it is summarised in the table below.

Table 8-1: Summary of the preferred option at this stage

Option	Description	Estimated capex ($2020/21)	Timing
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million	• 2025/26 under both demand forecasts
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 and Gunnedah substations as a double circuit	• $94 million	• 2029/30 under the central forecast • Not required under the low demand forecast
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $38 million	

We consider that a key determinant of the overall preferred option is the assumed build times, and ultimate commissioning dates, of each of the credible options since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided. Sensitivity analysis undertaken as part of this PADR shows that the results are relatively sensitive to the assumed commissioning dates for the options, e.g., if Option 3A was able to be delivered a year earlier, and Option 5B remained on the same timing, then Option 3A would have almost the same benefit as Option 5B.

While the timing sensitivities undertaken in this PADR are focused in particular on the rankings between the network and non-network options (rather than between the non-network options), we note that the assumed timings are also likely to be a key driver of the rankings between the non-network options.

We will therefore be focussing, internally and with third party proponents of non-network solutions, to firm up the assumed commissioning dates (and costs) for all options between now and the PACR, and to ensure that the assumed option timing is realistic in all cases. We expect that factors such as the assumed timing of land acquisition and planning approvals will be key to firm up and note that the current proposals display some diversity across these assumptions. It is expected that the assumed option timings in the PACR will reflect what option proponents are willing to commit to.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 177.

Rules clause	Summary of requirements	Relevant section(s) in the **PADR**
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;	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	6 & 7
	(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;	6.6
	(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

Appendix B Overview of existing electricity supply arrangements in the North West Slopes area

The North West Slopes area covers loads from Tamworth to Moree. The area is primarily supplied by 132 kV lines from the Tamworth 330/132 kV substation:

- Line 968 – Tamworth to Narrabri; and
- Line 969 – Tamworth to Gunnedah.

This part of the network is parallel to the 330 kV main system that interconnects the NSW and Queensland systems. Power flows on lines 968 and 969 are therefore affected by power flows on the NSW/Queensland interconnectors QNI and Directlink. At times of heavy power flows between the two states, the power flows on lines 968 and 969 can be significantly impacted by these main system flows.

The Narrabri and Gunnedah 132/66 kV substations supply Essential Energy loads in the area, with each substation having two 60 MVA 132/66 kV transformers. The Boggabri Coal and Maules Creek mines are also connected to the TransGrid 132 kV network via the Boggabri East and Boggabri North switching stations.

The current northern NSW electricity transmission network is shown in in Figure B-1 below with the area relevant for this RIT-T (the North West Slopes area) circled. The indicative location of the key forecast electricity loads that are discussed in this PSCR (and are publicly announced) are also shown.

Figure B-1: Northern NSW transmission network

Electricity demand in the North West Slopes is forecast to increase significantly over the next ten years, primarily due to planned connections of new mining and industrial loads in the area.

Electricity demand from expected new mining loads

VCM was approved by the Independent Planning Commission of NSW in August 2020 and is expected to be connecting to the distribution network. The project is located in the Gunnedah Coalfield, which is approximately 25 km north of Gunnedah.[40]

The scope of the VCM project includes the construction of a new 66 kV/11 kV substation that would be serviced by an existing 66 kV overhead powerline.[41] In light of the project's location, it will likely be supplied by Transgrid's Gunnedah 132/66kV substation. This new additional load is expected to require supply from 2023, with maximum electricity demand when fully operational of approximately 62,700 MWh per annum.[42]

Essential Energy has also advised that Santos NSW (Eastern) Pty Ltd is proposing to develop the Narrabri Gas Project. The project canvasses connecting to the NSW power grid by drawing power from the existing Wilga Park Power Station via a new power distribution line.[43] As a result, it would be supplied from Transgrid's Narrabri 132/66 kV substation. This is not included in Essential Energy's base demand forecast. The specific load forecasts for this project have not been included in this PADR due to confidentiality reasons.

The Narrabri Gas Project has received development consent from the Federal Government,[44] contingent on a number of environmental conditions being met. Santos has announced that this approval will allow them to begin an appraisal program ahead of a Final Investment Decision (FID) for the next phase of project development.[45] The FID date is currently scheduled for first half 2023 and, once approved, stage 1 of production will require supply from 2026.[46]

The development of a pipeline that links the Narrabri project to the existing Moomba to Sydney Pipeline is being investigated by the APA group.[47] The proposed route would commence to the north of the Pilliga National Park and Pilliga West State Conservation Areas, before extending west-southwest to connect to the Moomba to Sydney Pipeline at the Bundure mainline valve station, approximately 100 km west of Condobolin. Should this gas pipeline not be installed, it may affect the ability to fully develop the Narrabri Gas Project (which in-turn has implications for the certainty of the electricity demand projections).

General system demand in the North West Slopes area

We forecast there to be steady load increases for the North West Slopes area over the next twenty years, with Narrabri having the greatest expected load increase.

The two figures below present the actual 2019, as well as the forecast future, load duration curves (LDCs) and demand limits for the Narrabri and Gunnedah 66 kV Bulk Supply Points (BSP) along with the existing

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40 Australian Mining Monthly, *Vickery extension on track for 2021 construction completion,* 8 June 2019, available at: https://www.miningmonthly.com/development/international-coal-news/1364804/vickery-extension-on-track-for-2021-construction-completion; and Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Introduction*, p 1-1, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213410.742%20GMT.

41 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Project description*, p 2-18, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

42 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Project description*, p 2-31, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

43 Santos, *Narrabri Gas Project Environmental Impact Statement | Project description,* p 6-18, available at: https://majorprojects.accelo.com/public/1e6475194c440a225a59dddcb004fd53/Chapter%2006%20Project%20description.pdf

44 NSW planning portal website, https://www.planningportal.nsw.gov.au/major-projects/project/10716

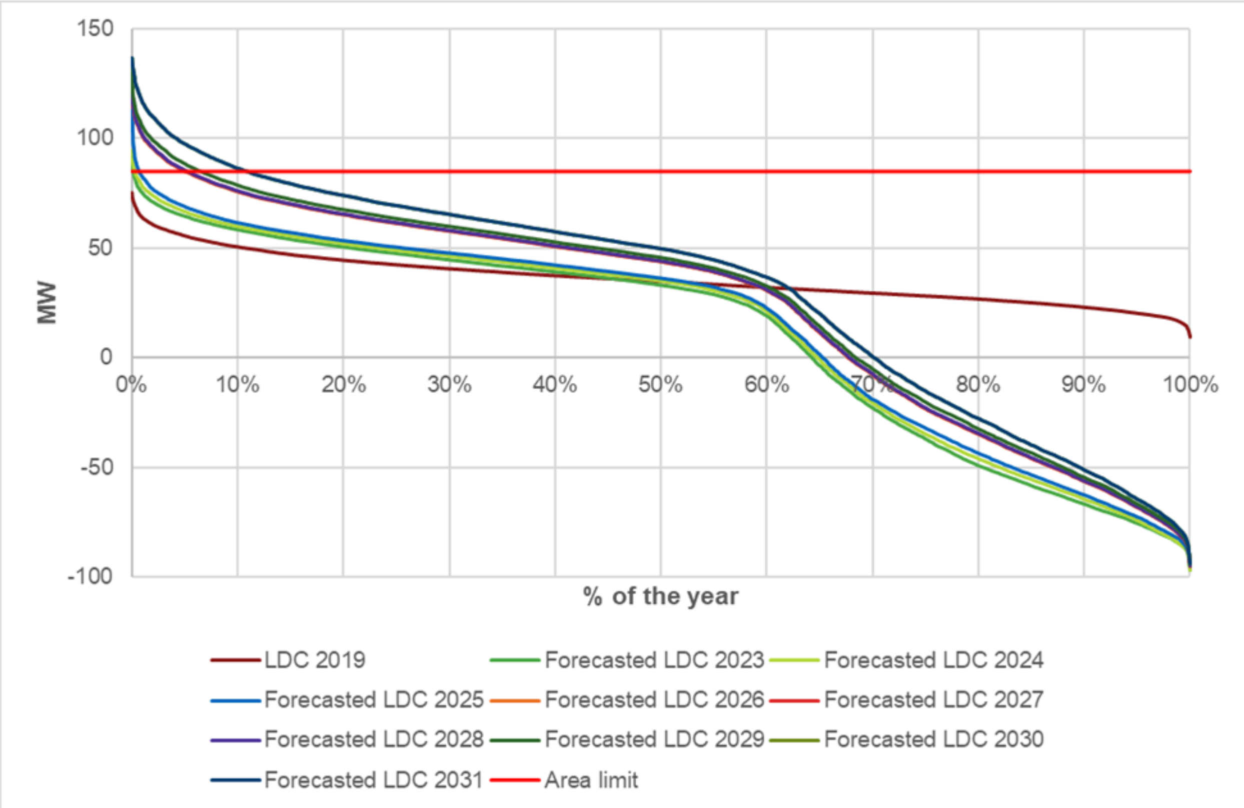
45 Santos' Narrabri Gas Project website, https://narrabrigasproject.com.au/2020/11/santos-welcomes-federal-signoff-on-narrabri-gas-project/

46 Santos 2020 Investor Day 1 Dec 2020, available as "Santos upgrades 2020 guidance" at: https://www2.asx.com.au/markets/company/STO

47 APA group website project updates, https://www.apa.com.au/about-apa/our-projects/western-slopes-pipeline/project-updates/

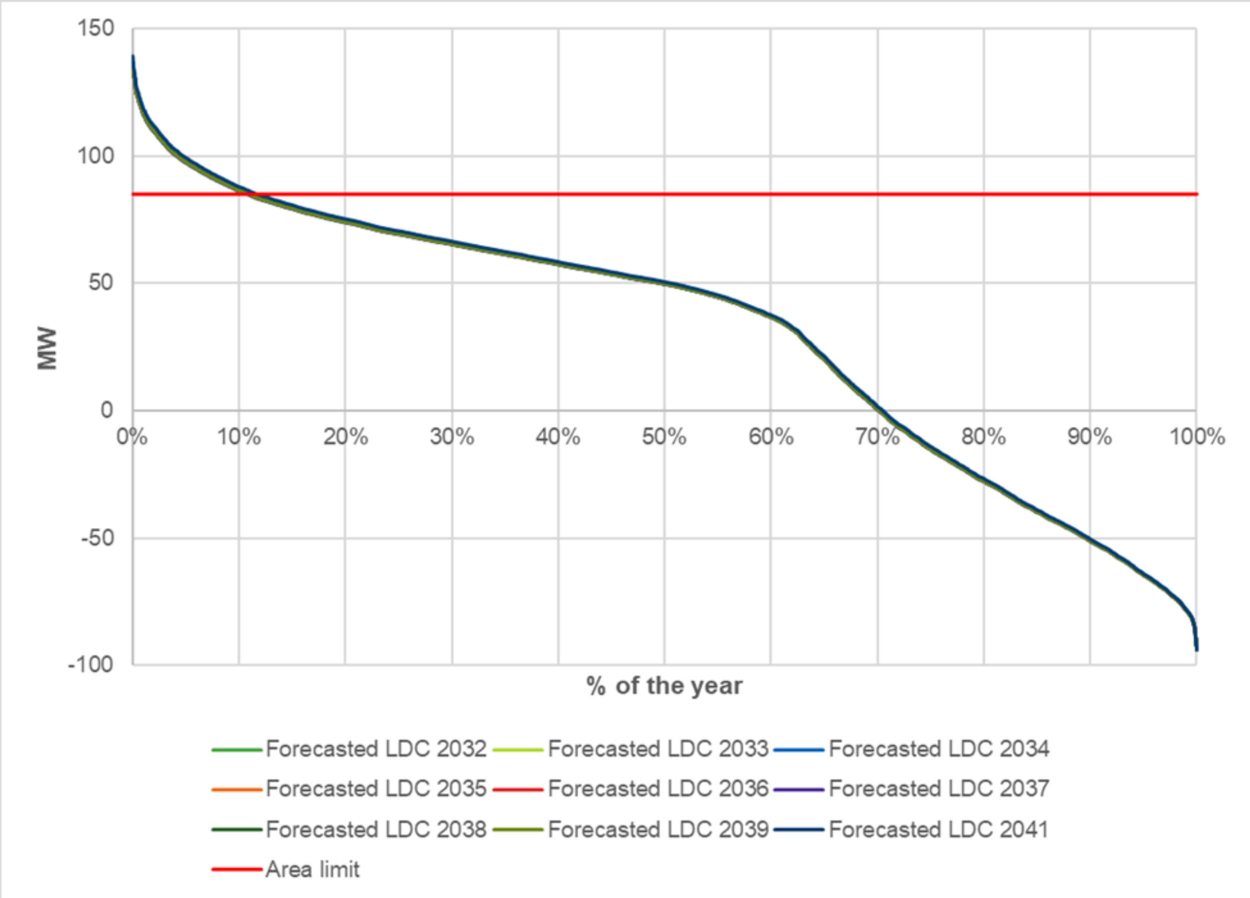
and forecast mining loads under the central scenario. The LDCs represent the net demand (i.e., total demand minus committed embedded renewable generation in the area) and show the significant expected increase in demand going forward under the central scenario, as well as how the thermal and voltage limits are expected to be exceeded an increasing percentage of the year if action is not taken. This data provides a visual representation of the load that could be at risk during a calendar year under the central scenario if action is not taken.[48]

Figure 8-2: Forecasted LDCs and demand limits for the North West Slopes area, actual 2019 and forecast to 2031 under the central demand forecasts



[48] The data shown in these LDCs is the aggregate of the load at Narrabri 66 kV, Boggabri North 132 kV, Boggabri East 132 kV and Gunnedah 66 kV, less the Gunnedah Solar Farm generation.

Figure 8-3: Forecasted LDCs and demand limits for the North West Slopes area, forecast 2031 to 2040 under the central demand forecasts



Renewable generation in the region

In addition to the longer-term voltage constraints, the forecast increased demand going forward is expected to also lead to thermal constraints, particularly at times of low renewable generation dispatch in the region.

There are a number of in-service and planned renewable generator connections in the northern NSW region. Table B-8-2 summarises these systems.

Table B-8-2: Current and planned renewable generation in the northern NSW region

Generating System	Connection location	Capacity (MW)	Status
Moree Solar Farm	Essential Energy's 66 kV Moree network	56	In-service
White Rock Wind and Solar Farm	White Rock substation	172.5	In-service
Gunnedah Solar Farm	9U3 Gunnedah to Boggabri East 132 kV line (close to Gunnedah)	110	Committed (expected commissioning in Q1 2022)
Tamworth Solar Farm	969 Tamworth to Gunnedah 132 kV line	65	Advanced*

**'Advanced' connection is in the connection application process with the connecting NSP.*

We note that there are also other new potential renewable energy generation projects proposed in the area that are not yet at a committed or advanced stage.

Additional renewable generation could assist with addressing/minimising the identified need as it can provide reactive support while generating active power subject to its voltage control strategy. We have taken account of in-service and committed renewable generation in assessing the identified need for this RIT-T.

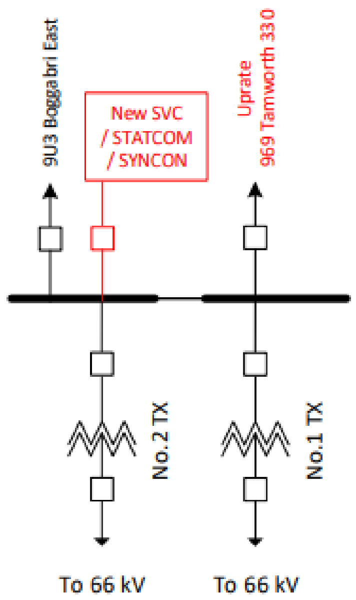
Appendix C Indicative line diagrams for each option

This appendix provides the line diagrams for each of the network elements of credible options considered in this PADR, as relevant. Existing elements are shown in black, while new elements are shown in red.

Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

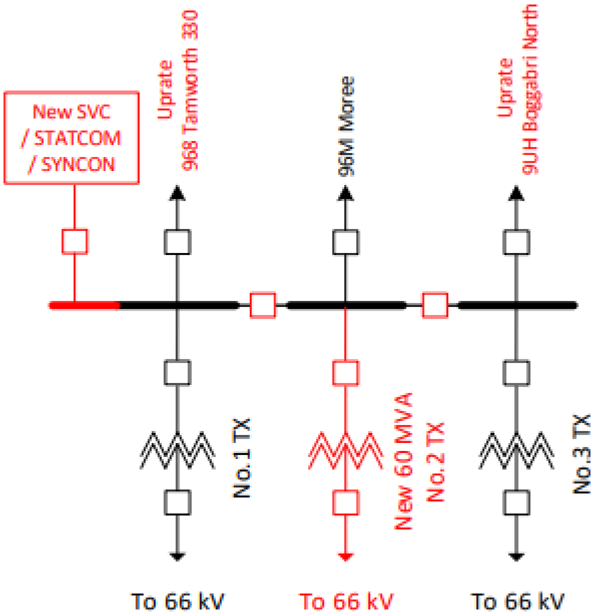
The indicative layout for the Gunnedah 132/66 kV substation under Options 1A and 1B is shown in Figure C-1 below.

Figure C-1: Indicative Gunnedah 132/66 kV substation layout under Options 1A and 1B



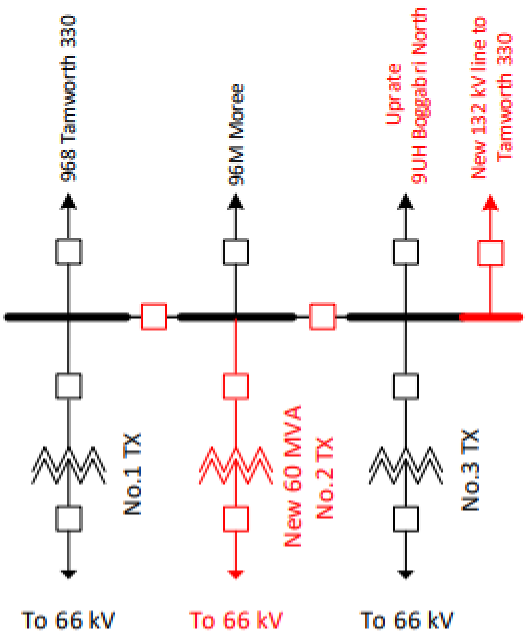
The indicative layout for the Narrabri 132/66 kV substation under Option 1A is shown in Figure C-2 below.

Figure C-2: Indicative Narrabri 132/66 kV substation layout under Option 1A



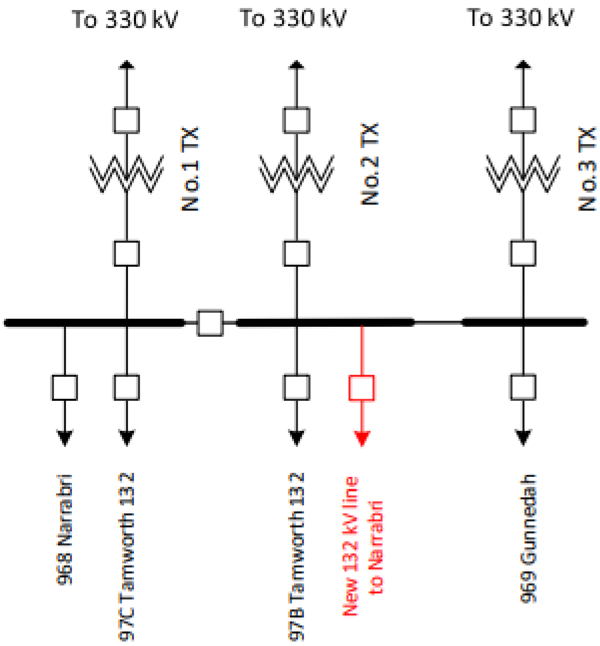
The indicative layout for the Narrabri 132/66 kV substation under Option 1B is shown in Figure C-3 below.

Figure C-3: Indicative Narrabri 132/66 kV substation layout under Option 1B



The indicative layout for the Tamworth 330/132 kV substation under Option 1B is shown in Figure C-4 below.

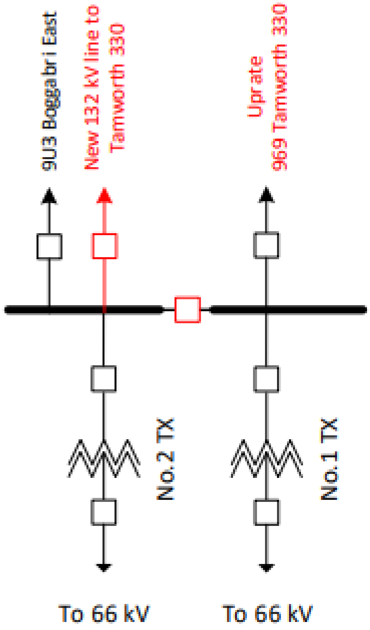
Figure C-4: Indicative Tamworth 330/132 kV substation layout under Option 1B



Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

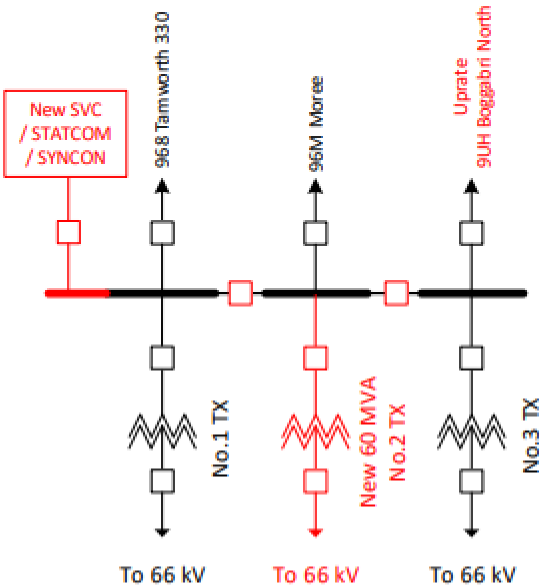
The indicative layout for the Gunnedah 132/66 kV substation under Option 2A is shown in Figure C-5 below.

Figure C-5: Indicative Gunnedah 132/66 kV substation layout under Option 2A



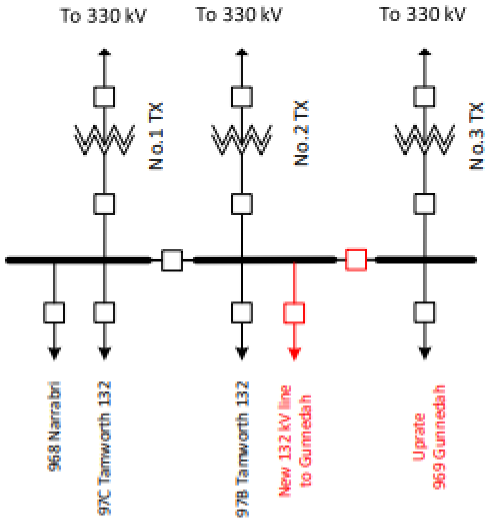
The indicative layout for the Narrabri 132/66 kV substation under Options 2A, 2B and 2D is shown in Figure C-6 below.

Figure C-6: Indicative Narrabri 132/66 kV substation layout under Options 2A, 2B and 2D



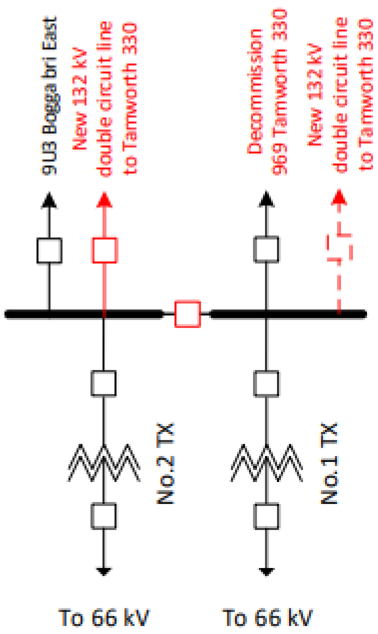
The indicative layout for the Tamworth 330/132 kV substation under Options 2A and 2C is shown in Figure C-7 below.

Figure C-7: Indicative Tamworth 330/132 kV substation layout under Options 2A and 2C



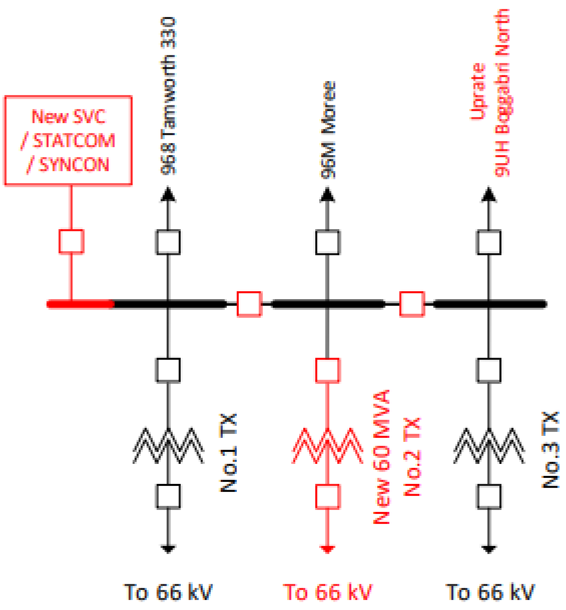
The indicative layout for the Gunnedah 132/66 kV substation under Option 2B is shown in Figure C-8 below.

Figure C-8: Indicative Gunnedah 132/66 kV substation layout under Option 2B



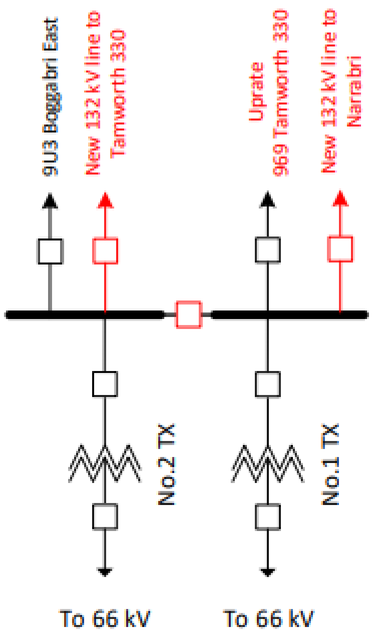
The indicative layout for the Tamworth 330/132 kV substation under Option 2B is shown in Figure C-9 below.

Figure C-9: Indicative Tamworth 330/132 kV substation layout under Option 2B



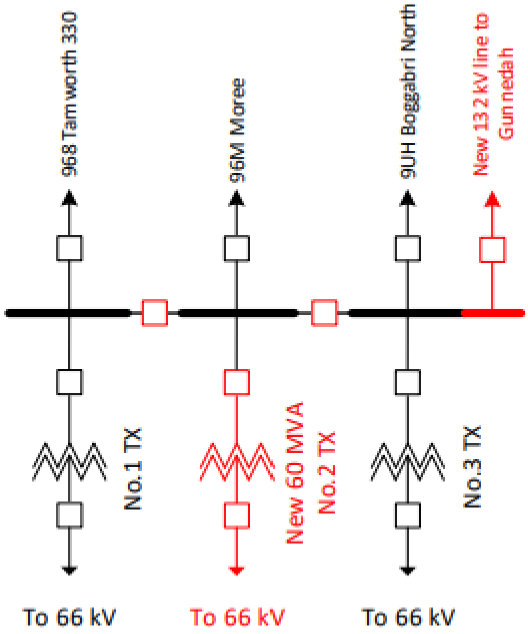
The indicative layout for the Gunnedah 132/66 kV substation under Option 2C is shown in Figure C-10 below.

Figure C-10: Indicative Gunnedah 132/66 kV substation layout under Option 2C



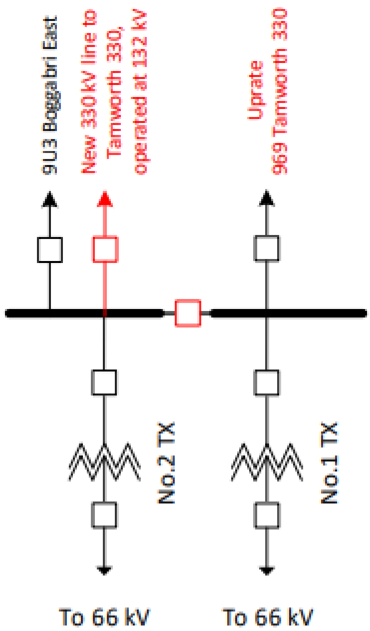
The indicative layout for the Narrabri 132/66 kV substation under Option 2C is shown in Figure C-11 below.

Figure C-11: Indicative Narrabri 132/66 kV substation layout under Option 2C



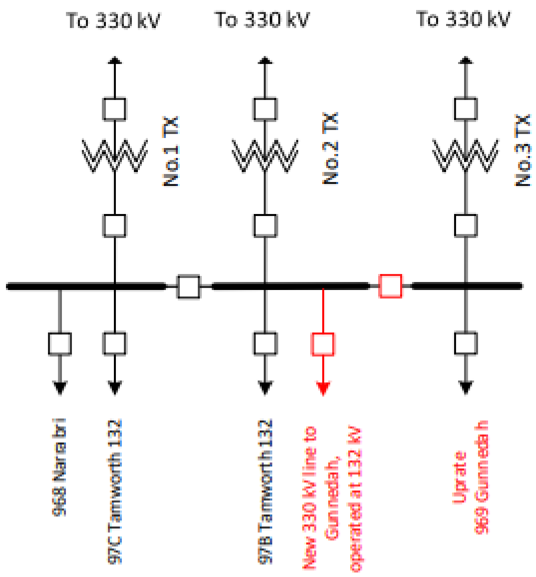
The indicative layout for the Gunnedah 132/66 kV substation under Option 2D is shown in Figure C-12 below.

Figure C-12: Indicative Gunnedah 132/66 kV substation layout under Option 2D



The indicative layout for the Tamworth 330/132 kV substation under Option 2D is shown in Figure C-13 below.

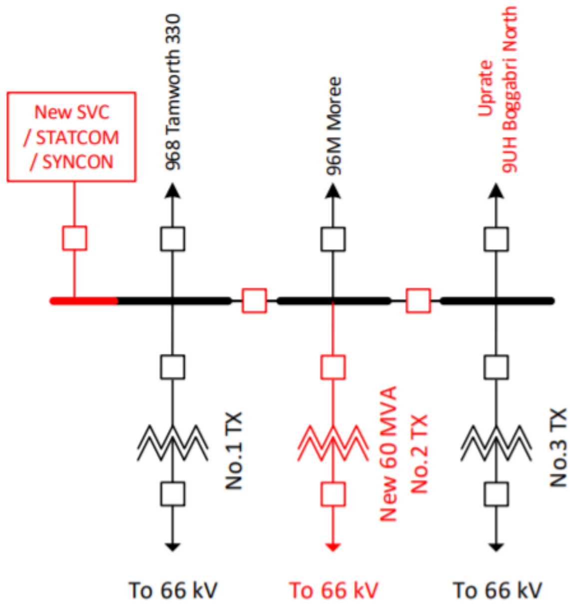
Figure C-13: Indicative Tamworth 330/132 kV substation layout under Option 2D



Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

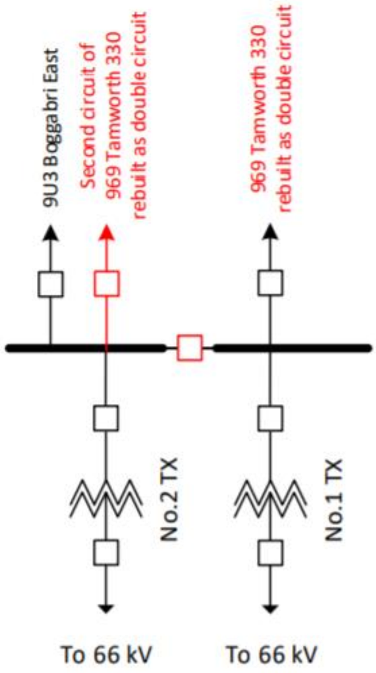
The indicative layout for the Narrabri 132/66 kV substation under Option 3A is shown in Figure C-14 below.

Figure C-14: Indicative Narrabri 132/66 kV substation layout under Option 3A



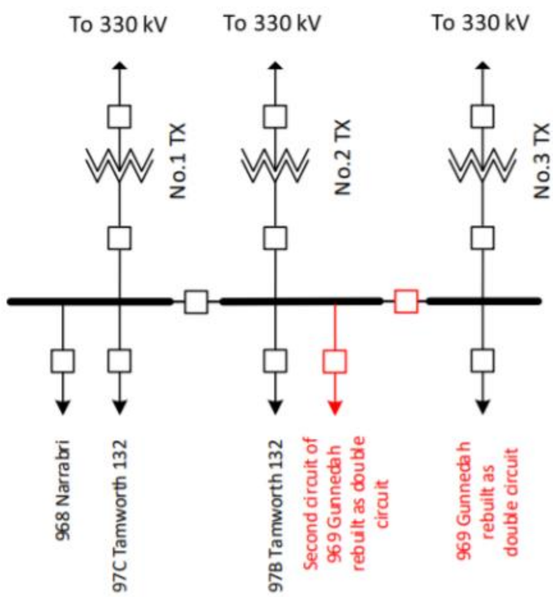
The indicative layout for the Gunnedah 132/66 kV substation under Options 3A and 3B is shown in Figure C-15 below.

Figure C-15: Indicative Gunnedah 132/66 kV substation layout under Options 3A and 3B



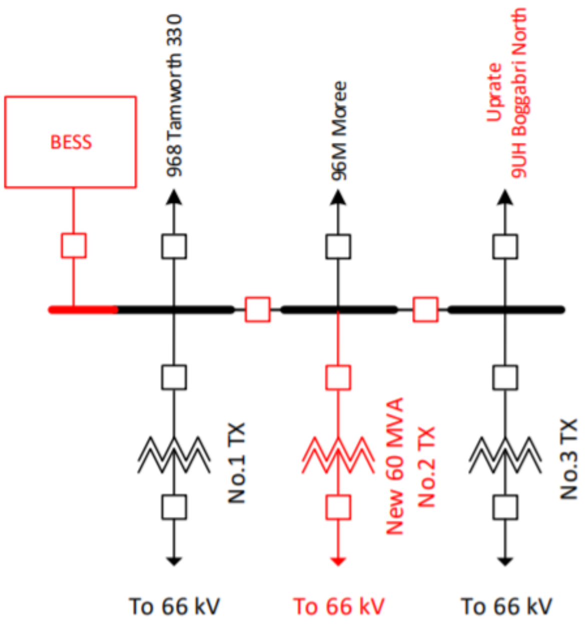
The indicative layout for the Tamworth 330/132 kV substation under Options 3A, 3B and 3C is shown in Figure C-16 below.

Figure C-16: Indicative Tamworth 330/132 kV substation layout under Options 3A, 3B and 3C



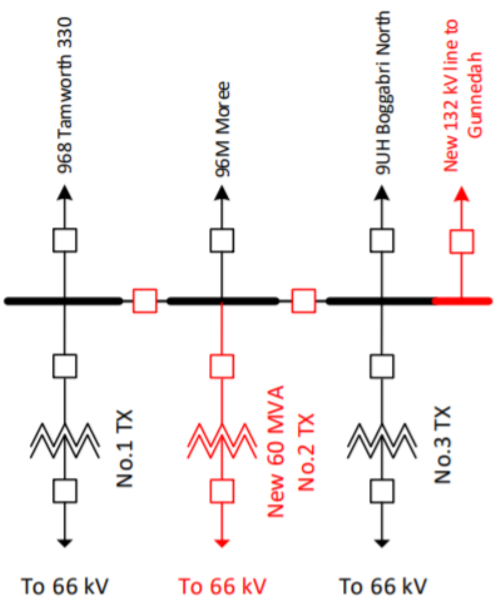
The indicative layout for the Narrabri 132/66 kV substation under Option 3B is shown in Figure C-17 below.

Figure C-17: Indicative Narrabri 132/66 kV substation layout under Option 3B



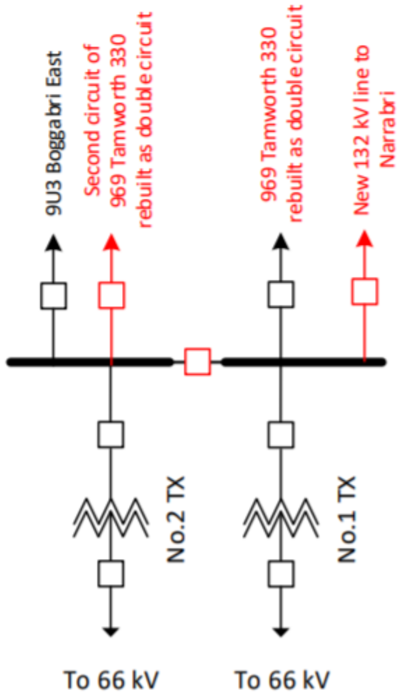
The indicative layout for the Narrabri 132/66 kV substation under Option 3C is shown in Figure C-18 below.

Figure C-18: Indicative Narrabri 132/66 kV substation layout under Option 3C



The indicative layout for the Gunnedah 132/66 kV substation under Option 3C is shown in Figure C-19 below.

Figure C-19: Indicative Gunnedah 132/66 kV substation layout under Option 3C



Appendix D Overview of the wholesale market modelling undertaken

As outlined in the body of this PADR, we have engaged EY to undertake the wholesale market modelling as part of this PADR.

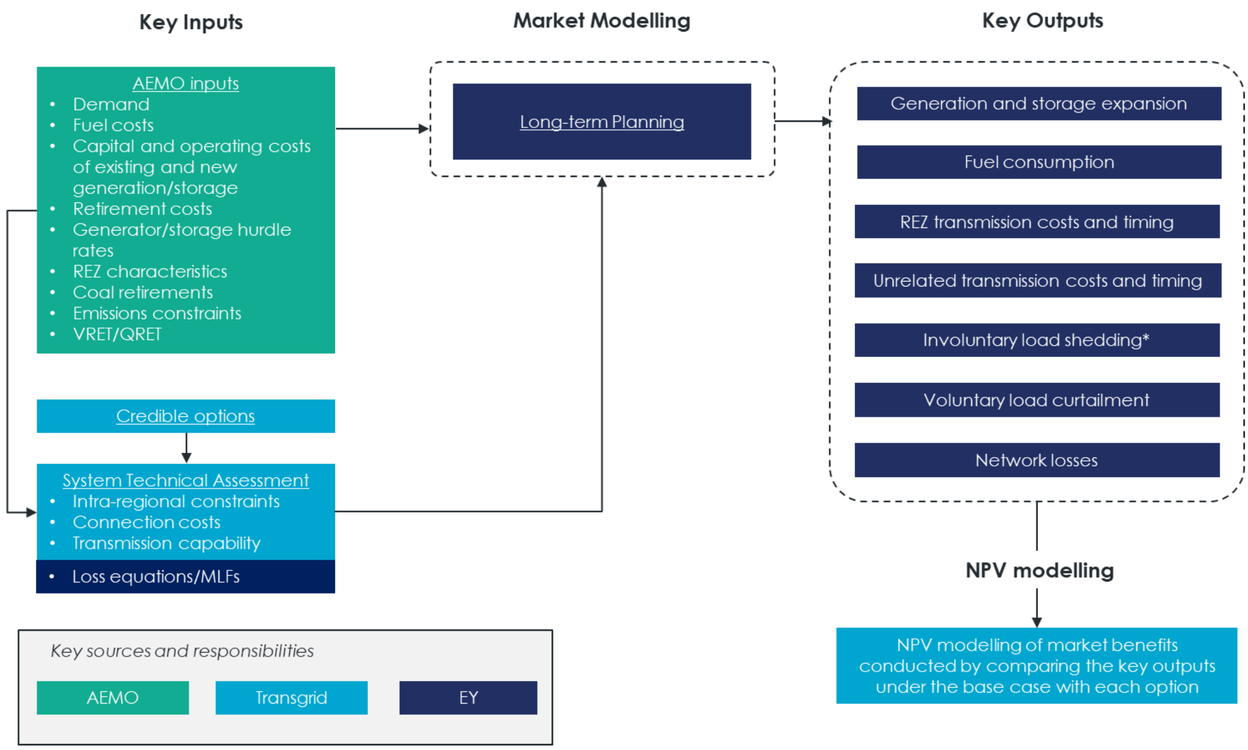
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving long-term investment planning, which identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reliability requirements, policy objectives, and technical generator and network performance limitations. This solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies.

We have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options align with the changes to the power system under each credible option. This assessment serves as an input to the wholesale market modelling exercises EY has undertaken (as outlined above).

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP.

Figure D-1 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure D-1: Overview of the market modelling process and methodologies



** As outlined in section 6.2, the avoided involuntary load shedding in the North West Slopes region of NSW has been estimated separately by Transgrid.*

The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PADR assessment.

Long-term Investment Planning

The Long-term Investment Planning's function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option drawing on assumptions regarding demand, emissions reduction and renewable energy targets, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator unplanned and planned outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators, Snowy Hydro-scheme and grid-scale batteries are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rate as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach being taken in the 2022 ISP (and was applied in the 2020 ISP and the inaugural 2018 ISP).[49]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its

[49] AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

minimum load, while gas-fired CCGT 'must run' plant is dispatched at or above its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

Modelling of diversity in peak demand

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010/11 to 2018/19.

Specifically, the key steps to accounting for this diversification are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation;
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the nine reference years are repeated sequentially throughout the modelling horizon; and
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the diversity of timing.

Modelling of intra-regional constraints

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting NSW into zones (NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model. The loss factors for each generation investment plan were computed on a five-year basis up to 2030-31 and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

Beyond 2030/31, the loss factors have been maintained at the same values as 2030-31, since network changes beyond that stage and additional renewable generation are becoming much less certain. However, this does not preclude generation investment if economic at any location.

Summary of the key assumptions feeding into the wholesale market exercise

The table below summarises the key assumptions that the market modelling exercise draws upon.

Table D-1: PADR modelled scenario key drivers input parameters

Key drivers input parameter	Progressive change scenario
Underlying consumption	ESOO 2021 (ISP 2022) - Progressive Change[50]
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Input and Assumptions Workbook[51] - Progressive Change
Retirements of coal-fired power stations	2021 Input and Assumptions Workbook - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030
Gas fuel cost	2021 Input and Assumptions Workbook - Progressive Change: Lewis Grey Advisory 2020, Central
Coal fuel cost	2021 Input and Assumptions Workbook - Progressive Change: WoodMackenzie, Central
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia, Northern Territory and off grid locations
NEM carbon budget to achieve 2050 emissions levels	2021 Input and Assumptions Workbook - Progressive Change: 932 Mt CO2-e 2030-31 to 2050-51
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030
Queensland Renewable Energy Target (QRET)	50% by 2030
Tasmanian Renewable Energy Target (TRET)	2021 Input and Assumptions Workbook: 200% Renewable generation by 2040
NSW Electricity Infrastructure Roadmap	2021 Input and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per the 2022 ISP 2 GW Pumped Storage Hydro by 2029-30.

50 AEMO, *National Electricity and Gas Forecasting*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 17 January 2022.
51 AEMO, *2021 Input and Assumptions Workbook*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed 17 January 2022.

Key drivers input parameter	Progressive change scenario
South Australia Energy Transformation RIT-T	Draft 2022 Integrated System Plan[52] – Progressive Change: EnergyConnect is commissioned by July 2025[53].
Western Victoria Renewable Integration RIT-T	Draft 2022 Integrated System Plan – Progressive Change: the Western Victoria upgrade commissioned by July 2025
HumeLink	Draft 2022 Integrated System Plan – Progressive Change: HumeLink commissioned by July 2035
Marinus Link	Draft 2022 Integrated System Plan – Progressive Change: 1st cable: commissioned by July 2029, and 2nd cable commissioned by July 2031
Victoria to NSW Interconnector Upgrade	Draft 2022 Integrated System Plan – Progressive Change: VNI Minor commissioned by December 2022.
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 Integrated System Plan – Progressive Change: QNI minor commissioned by July 2022
QNI Connect	Draft 2022 Integrated System Plan – Progressive Change: QNI Connect commissioned by July 2036
VNI West	Draft 2022 Integrated System Plan – Progressive Change: VNI West commissioned by July 2038.
Victorian SIPS[54]	Draft 2022 Integrated System Plan – Progressive Change: 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.
New-England REZ Transmission	Draft 2022 Integrated System Plan – Progressive Change: New England REZ Transmission Link commissioned by July 2027 and New England REZ Extension commissioned by July 2038
Snowy 2.0	Draft 2022 Integrated System Plan –Snowy 2.0 is commissioned by December 2026

[52] AEMO, *draft 2022 Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 17 January 2022.

[53] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report.* Available at: https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf. Accessed 28 June 2021. There are options for commissioning between 2022 and 2024. Limits also from this document.

[54] Victoria Government, Victorian Big Battery, Available at: https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a, Accessed 1 July 2021.