Transgrid

Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas

RIT-T - Project Assessment Conclusions Report [Amended]

Region: Central West New South Wales

Date of issue: 31 January 2023

People. Power. Possibilities.

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Executive summary

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Bathurst, Orange and Parkes area of central west New South Wales. An initial Project Assessment Conclusions Report (PACR) was released for this RIT-T on 30 June 2022 (referred to throughout this document as the 'initial PACR').

On 1 August 2022, the Australian Energy Regulator (AER) received a dispute notice from the Public Interest Advocacy Centre (PIAC), contending that Transgrid may have incorrectly applied the RIT-T in the initial PACR. On 29 November 2022, the AER released its determination on the dispute and has required Transgrid to amend the PACR in a number of areas by 1 February 2023.

This amended PACR therefore updates the assessment and PACR in-line with the AER dispute determination. The amended PACR only varies from the initial PACR to the extent necessary to reflect the changes made to the scenario assumptions in light of the AER determination, to present the revised results and to provide the additional information requested by the AER. We have engaged with the AER on the approach for amending the PACR and consider that this document fully aligns with the direction provided in the determination and those subsequent discussions.

The time taken to address the RIT-T dispute and may change the availability of network and non-network solutions beyond the expected timing considered in this PACR. This will be assessed during the competitive procurement process and commercial negotiations with non-network proponents. However, we consider that any change is likely to equally apply to both network and non-network options and will therefore not materially impact the relative benefits or ranking of options presented in this amended PACR.

Overview

The preferred option identified in this amended PACR remains unchanged from the initial PACR and involves a non-network solution provided through new Battery Energy Storage Systems (BESS) at Parkes and Panorama along with the installation of static synchronous compensators (STATCOMs) at Parkes and Panorama or a synchronous condenser (as a network investment) at Parkes in the near-term. It also involves a new 132 kV line between Wellington and Parkes in the future, with the date of this line depending on outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 7D and Option 7E in the PACR, and reflect the proposed BESS components followed by the network investment outlined above. These options are found to deliver approximately $2,550 million and $2,544 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $466 million for the top-ranked solely network option (Option 3).

The proposals of the other three non-network proponents (Option 7A, Option 7B and Option 7C, which variously involve BESS and other technologies) have been found to deliver lower net benefits than the two top-ranked options (when coupled with the later 132 kV Wellington-Parkes line), but also to be ranked significantly ahead of Option 3.

The non-network solutions will provide up to 50 MVAr at Parkes and up to 30 MVAr at Panorama of dynamic reactive support by 2025 to manage voltage variations during high demand periods. Options with non-network solutions generally have higher net benefits because they can be deployed an estimated one to two years earlier than the pure network options, avoiding significant unserved energy in that period.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider all five proponents should be involved in these negotiations (i.e., including the proponents for Option 7A, Option 7B and Option 7C, which have lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when non-network support can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process, compared to two, will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or
2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3 (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the Bathurst, Orange and Parkes area and ultimately likely cost all NSW electricity customers more in the long-run.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T)

All non-network options, as well as Option 3, are expected to generate sufficient benefits to recover their costs within two years of commissioning their respective long-term solutions (under the weighted results and in present value terms).

The identified need driving investment

Our latest forecasts indicate that electricity demand is expected to increase substantially in the Orange and Parkes areas going forward due to expected demand growth associated with the expansion of some existing large mine loads in the area, the planned connection of new mine/industrial loads and general load growth around Parkes, including from the NSW government's Parkes Special Activation Precinct (SAP).

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.[1] The NER also require the power

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

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.[2]

We have undertaken planning studies that show that the current central west 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. Specifically, we forecast significant under-voltage conditions in this region of our network if action is not taken.

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

This RIT-T therefore examines various 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. 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.

Benefits from the options considered in this PACR

Without action, voltage-limited constraints will have to be applied in the 132 kV supply network that will lead to substantial levels of unserved energy to end customers. We are taking action under this RIT-T in order to avoid this outcome. All of the credible options have been designed to maximise the avoided unserved energy expected and ensure compliance with the requirements of the NER.

In addition, some of the credible options assessed also affect the wholesale electricity market. In particular, seven of the options involve grid-connected BESS, two of which also involve solar PV (Option 7A and Option 7B), that are expected to introduce new entities trading in the wholesale market, eg, dispatching into the National Electricity Market (NEM) outside of the allocation of storage needed to meet network support commitments.

Both the benefits from the provision of reliable supply to the Bathurst, Orange and Parkes area and wider wholesale market benefits have been estimated as part of this PACR.

Key developments since the PADR have been reflected in the PACR

There have been a number of key developments since the Project Assessment Draft Report (PADR) was released in February 2022, which impact the analysis in this RIT-T. In particular:

- demand forecasts have been updated based on additional information provided by proponents of new or expanded spot loads, as well as updated information on general load growth from Essential Energy;
- forecasts of when voltage limits are expected to be breached in light of the revised demand forecasts have been updated;

2 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.

- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO's 2022 Integrated System Plan (ISP) and is now focused on the Step Change, Progressive Change and Hydrogen Superpower scenarios (the scenario weightings have also been updated to be consistent with the 2022 ISP);
- a number of updates have been made to the non-network options in the PADR (Option 7A, Option 7B, Option 7C and Option 7D), including to reflect new information provided by proponents;
- inclusion of a new non-network option (Option 7E) in the assessment following a submission to the PADR;
- the assumptions regarding how BESS components can trade in the wholesale market outside of their network support obligations have been refined; and
- there have been a number of updates to the network options, including in relation to their timing, size and cost.

The demand forecasts feeding into the identified need for this RIT-T have been updated since the PADR to reflect the latest Essential Energy demand forecasts available at the time of preparing the initial PACR and updated information provided by external parties on the current state of key projects at the time of the initial PACR. Specifically:

- Essential Energy provided revised general demand forecasts, which now include the demand associated with a mining load that Transgrid included in its demand forecasts for the PADR;
- Additional information provided by one of the confidential mining loads since the PADR regarding the commitment status of an expansion they are expecting to make has led to an increased amount of load for this mine being included in the central and high demand forecasts:
  - Further potential increases in that mining load have been included as a sensitivity, rather than being reflected in the high scenario, based on the information available at the time of the PACR;
- there has been a reduction in the demand forecast of a third confidential mining load since the PADR, which has been reflected in all three demand forecasts;
- a fourth confidential mining load provided a revised demand forecast in response to the PADR that indicates a shorter peak demand period and reduced demand at all other times (particularly after 2025/26), which has been reflected in all three demand forecasts; and
- further discussions with the NSW government have resulted in no change from the PADR being assumed for the demand forecast associated with the Parkes SAP.

We received submissions from eleven parties in response to the PADR. While submissions covered a range of topics, there were six main topics that emerged:

- a new non-network option was proposed by one submitter (and has been included in the PACR assessment as a new Option 7E);
- further details regarding earlier proposed non-network options were provided by proponents;
- uncertainty around the demand forecasts;
- the appropriateness of the use of non-network options to address voltage constraints;
- estimating the market benefits, including use of the ISP scenarios, weighting of the scenarios and inclusion of additional benefits; and
- proposed modifications to the network options.

The key matters raised in public submissions relevant to the RIT-T assessment are summarised in this PACR, together with our responses and how the matters raised have been reflected in the assessment.

Many of the submissions were confidential and so we have engaged directly with those parties on the points raised.

We note that this amended PACR does not reflect any further changes to the assumptions since the initial PACR, other than those made as a consequence of the AER's dispute determination. This is consistent with the AER's view that, as a principle, they expect Transgrid to apply the same information that was available at the time of the PACR, unless Transgrid considers that there has been a material change in circumstances as defined in the NER. We have however presented a sensitivity with increased costs for the network component of the options, to reflect our latest unit rates, in line with our revised Regulatory Proposal.

The PACR assessment covers four different types of credible options

The credible network options assessed in this PACR differ in the near-term by where, how and when new capacity is added to the central west network going forward. Specifically, the network options differ by:

- how reactive support is provided in the short-term (including through traditional transmission network elements as well as through installing dynamic reactive power devices);
- how much reactive support is provided in the short-term; and
- whether a new transmission line is ultimately built over the longer-term.

We have also assessed options involving the use of non-network components. Each of the five non-network solutions has been modelled in terms of its ability to efficiently defer or avoid the short-term reactive support requirements at Panorama and/or Parkes for the preferred network option (i.e., Option 3).

The credible options considered in the PACR assessment have been refined since the PADR, to reflect:

- Option 5 and Option 6 (both involving grid-owned BESS) only being expected to be able to arbitrage outside of the peak demand periods in Summer and Winter;[3]
- slightly resized network components across the options due to the revised load forecasts; and
- the Parkes capacitor banks being removed from the background assumptions (base case) due to changes in the status of that separate project.

Table E-1.1 below summarises each of the credible options assessed in the PACR.

Table E-1.1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)		
1A/1B[4]	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Wellington to Parkes 132 kV line	• $123 million[5]

3 Compared to at all times, and using all of their capacity, assumed in the PADR assessment.

4 In the PSCR this option distinguished between Option 1A and 1B because of the then anticipated future stages of developments. These later stages are no longer considered necessary and so these two options have been collapsed into one option. The option naming has been retained in the PADR and in this PACR for consistency.

5 Please note that the estimated cost of the Wellington to Parkes line is slightly higher for Option 1A/1B than it is for Option 3, Option 5, Option 7A, Option 7B, Option 7C, Option 7D and Option 7E since, for Option 1A/B, the new Wellington-Parkes line connection is the first work undertaken at Parkes and so it includes the scope to add 132 kV bus section circuit breakers (which is included in the earlier stages of Option 3, Option 5, Option 7A, Option 7B, Option 7C, Option 7D and Option 7E).

Option	Description	Estimated capex ($2020/21)
Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)		
1C	• Initial synchronous condenser at Parkes 132 kV (25 MVA)	• $28 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Second synchronous condenser at Parkes 132 kV (25 MVA)	• $26 million
	• Third synchronous condensers at Parkes 132 kV (35 MVA)	• $32 million
Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)		
3	• Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 x 25 MVA)	• $84 million
	• Wellington to Parkes 132 kV line	• $121 million
Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
4	• Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 x 25 MVA)	• $84 million
	• New Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (35 MVA)	• $27 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)		
5	• 25 MVAr synchronous condensers at Parkes + 20 MW (40 MWh) BESS at Parkes + 25 MW (50 MWh) BESS at Panorama	• $140 million
	• Wellington to Parkes 132 kV line	• $121 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
6	• 25 MVAr synchronous condensers at Parkes + 20 MW (40 MWh) BESS at Parkes + 25 MW (50 MWh) BESS at Panorama	• $140 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (35 MVA)	• $27 million
Combination of non-network solutions with the top-ranked network option (Option 3)		
7A	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line

Option	Description	Estimated capex ($2020/21)
7B	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7C	• Synchronous condenser at Parkes 132 kV (2 x 25 MVA) • BESS at Panorama • Wellington to Parkes 132 kV line	• $55 million for the synchronous condensers • Confidential for the non-network components • $121 million for the line
7D	• BESS and STATCOM at Parkes • BESS and STATCOM at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components (including the STATCOMs) • $121 million for the line
7E	• BESS at Parkes • BESS at Panorama • 25 MVAr synchronous condenser at Parkes • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $41 million for the synchronous condensers • $121 million for the line

The synchronous condensers at Parkes under Option 7C and Option 7E are network components.

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects.

Three scenarios have been assessed

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this amended PACR assessment, which differ in terms of the key drivers of the estimated net market benefits. While the scenarios in the initial PACR were designed to comprehensively test the range of net benefits that can be expected from the credible options, they have now been updated in-line with the AER dispute determination to align with those in the AEMO's 2021 Inputs, Assumptions and Scenarios Report (IASR), which underpins the 2022 Integrated System Plan (ISP).

Specifically, the three scenarios now reflect the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR and only vary by local spot load forecasts and new local renewable generation assumptions (since these two parameters have material impacts on the assessment of the options). The scenarios no longer vary the assumed network or non-network capital costs, the VCR or discount rate. This approach has been discussed and agreed with the AER following their dispute determination.

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered. It also shows where there has been a change in an assumption from the initial PACR following the AER dispute determination (where the initial assumption is shown italicised in parentheses).

Table E-1.2: Summary of scenarios (and comparison with initial PACR)

Variable	Step Change	Progressive Change	Hydrogen Superpower
Network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Non-network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Demand	Central demand forecast	Low demand forecast	High demand forecast
New renewable generation in the area	In-service generators from Appendix B.	In-service generators from Appendix B. *(All in-service, commissioning, committed and advanced generators)*	All in-service and advanced generators from Appendix B. *(In-service, commissioning and committed generators)*
Wholesale market benefits estimated	EY estimated based on the Step Change 2022 ISP scenario	EY estimated based on the Progressive Change 2022 ISP scenario	EY estimated based on the Hydrogen Superpower 2022 ISP scenario
VCR[6]	$54.54/kWh	$54.54/kWh *($38.18/kWh)*	$54.54/kWh *($70.91/kWh)*
Discount rate	5.50%	5.50% *(7.50%)*	5.50% *(1.96%)*

The wholesale market modelling has been updated since the PADR and we now model the market benefits of the options (where relevant) across the three ISP scenarios. We have also weighted each of the scenarios for this RIT-T based on the ISP weightings, i.e.:

6 The VCRs have been updated since the PADR to reflect the updated underlying demand forecasts, i.e., the load that would be affected under the base case. However, we note that this update has had only a minor impact on the estimated VCRs.

- 52 per cent to the Step Change scenario;
- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

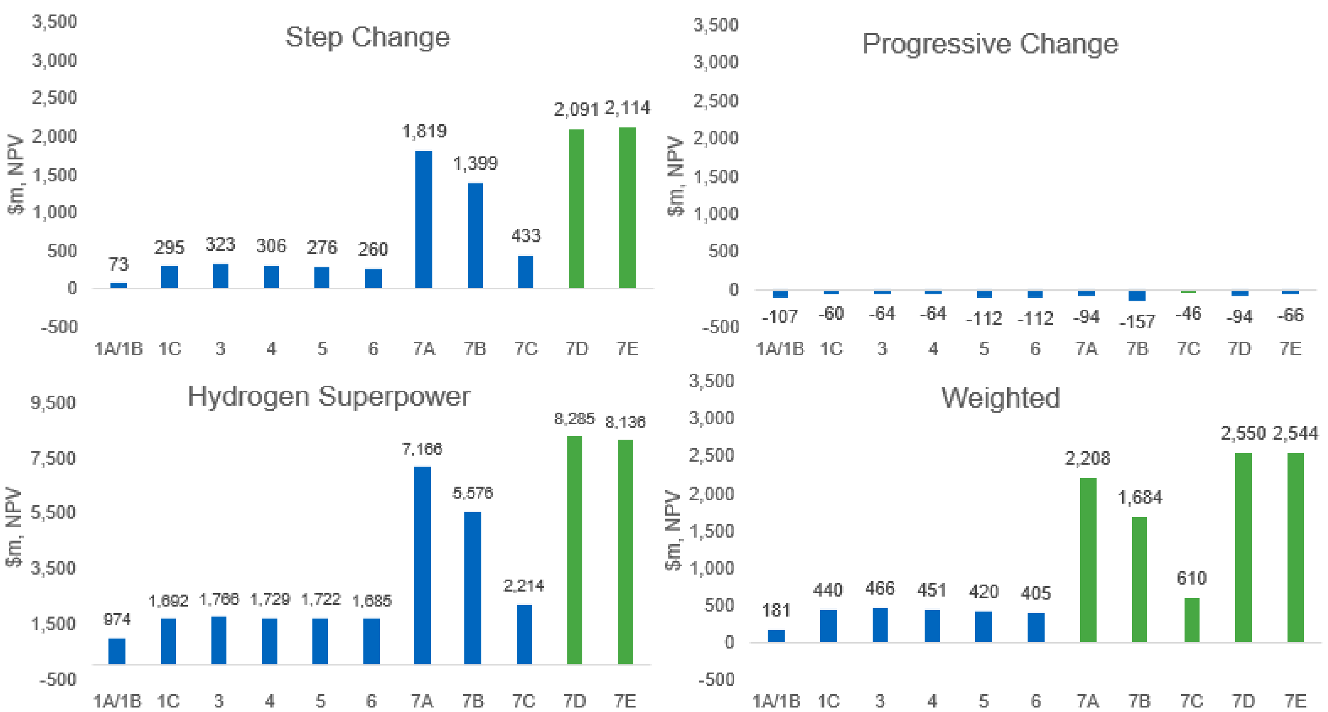
We have also investigated the sensitivity of the results to alternate weightings as part of this PACR (and they are found not to be sensitive).

The preferred option involves the use of BESS in the short-term coupled with network investment as demand grows

The preferred option identified in this amended PACR is the same as the initial PACR and involves the use of a non-network solution provided via new BESS at Parkes and Panorama and the installation of either STATCOMs at Parkes and Panorama or a synchronous condenser (as a network investment) at Parkes in the near-term. It also involves a new 132 kV line between Wellington and Parkes in the future, with the date of this line depending on what happens with outturn demand forecasts.

The proposals of two separate third party BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 7D and Option 7E in the PACR and are found to deliver approximately $2,550 million and $2,544 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compared to $466 million for the top-ranked solely network option (Option 3).

Figure E-1-1: Estimated net benefits for each scenario



The proposals of the other three BESS proponents have been found to deliver lower net benefits than these two options but still to be significantly ahead of Option 3. Specifically, these options are found to have net benefits that are between $144 million and $1,741 million greater than Option 3.

While Option 3 is found to have net benefits that are approximately 3 per cent greater than the next best network option (Option 4), it is found to have the lowest expected capital cost of all the solely network options (9 per cent lower than Option 1C and 14 per cent lower than Option 4 (the two next lowest cost network options)), which is why it is considered the preferred network option and is the network option the non-network options have been coupled with.

The rankings of the options on a weighted basis has not changed in the amended PACR analysis relative to the initial PACR.

Almost all of the estimated gross benefits are derived from avoided unserved energy, which make up between 89 and 100 per cent of the total gross benefits of Options 7A-7E on a weighted basis (and 100 per cent of the total gross benefits of Option 3, since this option does not affect the wholesale market). We note also that we have applied a conservative approach to valuing these benefits, whereby all unserved energy in the later years of the assessment period is not valued (since it is common to all options), in order to enable the most meaningful comparison between options.

All the non-network options are ranked above any of the network options in the Step Change scenario, Hydrogen Superpower scenario and on a weighted basis. The Progressive Change scenario would need to be given an unreasonably high weighting in order to change the conclusion of this PACR. Specifically, we find that the Progressive Change scenario would need to be given a weighting of approximately 95 per cent in order for a non-network option to be ranked below any of the network options.[7] We consider this unlikely.

Further information and next steps

This amended PACR represents the final formal stage in the RIT-T process, and follows the AER's determination on the dispute lodged in response to the initial PACR.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3 should be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to

[7] We note that this weighting does not change if we value all avoided unserved energy in the assessment, i.e., if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR.

meet (i.e., Schedule 5.1.4 of the NER) are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the Bathurst, Orange and Parkes area and ultimately likely cost all NSW electricity customers more in the long-run.

We note that the Rules regarding a 'material change in circumstances', and the ability to include 'reopening triggers'[8] in a PACR have recently been considered by the Australian Energy Market Commission.[9] The final rule requires RIT-T proponents of projects with an estimated cost of more than $100 million to develop reopening triggers that clearly indicate whether there has subsequently been a material change in circumstances following completion of the RIT-T.[10] While the new rule requirements do not apply to this RIT-T, consistent with the final rule made, we consider the events above to constitute two elements of an effective reopening trigger for this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that Option 3 should instead be progressed (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

As stated in our recently submitted Revised Revenue Proposal for the 2023-2028 period, we intend to rely solely on a non-network solution comprising of a BESS at Parkes and Panorama and the installation of static synchronous compensators (STATCOMs) at Parkes and Panorama (as a non-network solution). Given the need to still finalise a network support agreement, we have included the alternative network investment (i.e., a synchronous condenser) that could be coupled with a non-network BESS, as a contingent project for the upcoming regulatory period. We have also included a fully-network option as a contingent project in case the non-network solutions are found not to be technically feasible, or if we are unable to conclude network support agreements in time to meet our regulatory obligations, although we are working hard to avoid this outcome. More information on our 2023-28 Revised Revenue Proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Bathurst, Orange and Parkes reliability project.'

8 We note that what was originally referred to as 'decision rules' at the time of the initial PACR has been relabelled as 'reopening triggers' by the AEMC to differentiate this approach from the decision rules AEMO uses for the ISP. See AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. 9.

9 AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.

10 AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. ii.

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1. Introduction

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Bathurst, Orange and Parkes area of central west New South Wales. This PACR represents the final stage in the RIT-T process and follows the Project Assessment Draft Report (PADR) released on 18 February 2022. An initial Project Assessment Conclusions Report (PACR) was released for this RIT-T on 30 June 2022 (referred to throughout this document as the 'initial PACR'). This PACR is an amended version of that report.

This amended PACR replaces the initial PACR in light of the dispute raised

On 1 August 2022, the Australian Energy Regulator (AER) received a dispute notice from the Public Interest Advocacy Centre (PIAC), contending that Transgrid may have incorrectly applied the RIT-T in the initial PACR.

On 29 November 2022, the AER released its determination on the dispute and has required Transgrid to amend the initial PACR by 1 February 2023. Specifically, the AER determination requires Transgrid to amend the PACR to:[11]

- include scenarios from the 2021 Inputs, Assumptions and Scenarios Report (IASR) and only use different scenarios where Transgrid can provide demonstrable reasons for that approach;
- demonstrate if alternate scenarios are reasonable such that a reasonable range of plausible states of the world is generated;
- include a common discount rate across all scenarios in the updated cost benefit analysis based on the discount rate in AEMO's most recent IASR, or otherwise provide demonstrable reasons for why a variation from this value is necessary; and
- include an updated cost benefit analysis, including updated sensitivity analysis, for each credible option for each reasonable scenario and its impact on the ranking of the credible options assessed in the PACR.

The AER determination recommended that the amended PACR include sensitivity analysis associated with varying the estimated capital costs of the credible options and the discount rate. It also recommended that the amended PACR include information to enable interested parties to further understand the calculation of the VCR values, the methodology used to estimate capital costs and the basis for including forecast spot loads across the scenarios.

This amended PACR therefore updates the assessment and PACR in-line with the AER dispute determination. The amended PACR only varies from the initial PACR to the extent necessary to reflect the changes made to the scenario assumptions, the revised results and to provide the additional information requested by the AER. We have engaged with the AER on the approach for amending the PACR and consider that this document fully aligns with the direction provided in the determination and subsequent discussions.

As is set out in our 2022 Transmission Annual Planning Report (TAPR), the latest forecasts indicate that electricity demand is expected to increase substantially in the Orange and Parkes areas going forward.[12] This is mainly due to expected demand growth associated with the expansion of some existing large mine loads in the area, the planned connection of new mine/industrial loads and general load growth around Parkes, including from the NSW government's Parkes Special Activation Precinct (SAP).[13]

11 AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 31-32.
12 Transgrid, *Transmission annual planning report*, 2022, p 49.
13 https://www.nsw.gov.au/snowy-hydro-legacy-fund/special-activation-precincts/parkes-special-activation-precinct

Our power system studies forecast that the expected load growth in the Orange and Parkes areas will reach the voltage stability limits of the existing 132 kV supply network in the central west 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.[14] 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.[15]

We have undertaken planning studies that show that the current central west 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. Specifically, we forecast significant under-voltage conditions in this region of our network if action is not taken.

This RIT-T therefore examines various 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.

1.1. Purpose

The purpose of this PACR is to:

- identify and confirm the market benefits expected from the various options for maintaining the required reliability of supply in the Bathurst, Orange Parkes area over the long-term;
- summarise the submissions received on the PADR and developments since the PADR was released and highlight how these have been taken into account in the RIT-T analysis;
- describe the options assessed under this RIT-T, including how these have been shaped as part of the consultation process;
- present the results of the updated 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 overall preferred option under the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, a key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

A supplementary market modelling report was published on our website alongside the initial PACR, and remains relevant to this amended PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this amended PACR.

The credible options outlined in this PACR 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

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

15 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.

of these options in order to identify the most efficient series of investments to meet network needs over the long-term.

1.2. Further information and next steps

This amended PACR represents the final stage in the RIT-T process, and follows the AER's determination on the dispute lodged in response to the initial PACR.

The preferred option identified in this amended PACR remains the same as that identified in the initial PACR and involves the use of Battery Energy Storage Systems (BESS) at Parkes and Panorama non-network solutions and the installation of STATCOMs at Parkes and Panorama or a synchronous condenser (as a network investment) at Parkes in the near-term. It also involves a new 132 kV line between Wellington and Parkes in the future, with the date of this line depending on what happens with outturn demand forecasts.

The BESS proposals of two separate third party BESS proponents have been found to be ranked effectively equal in the PACR assessment (these options are referred to as Option 7D and Option 7E in this PACR). We will now enter into a competitive procurement process and commercial negotiations with proponents for a network support contract and seek to put in place a contract with one of these parties. The specific details of these BESS proposals have not been presented in this PACR to preserve the confidentiality requested by the proponents.

Progression of Option 7D or Option 7E will require the successful conclusion of a binding network support agreement between Transgrid and a BESS proponent that is acceptable to the AER. If this does not occur then we consider that the next highest ranked option, Option 3, is to be considered the preferred option under this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that Option 3 should instead be progressed (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

As stated in our recently submitted Revised Revenue Proposal for the 2023-2028 period, we intend to rely solely on a non-network solution comprising of a BESS at Parkes and Panorama and the installation of static synchronous compensators (STATCOMs) at Parkes and Panorama (as a non-network solution). Given the need to still finalise a network support agreement, we have included the alternative network investment (i.e., a synchronous condenser) that could be coupled with a non-network BESS, as a contingent project for the upcoming regulatory period. We have also included a fully-network option as a contingent project in case the non-network solutions are found not to be technically feasible, or if we are unable to conclude network support agreements in time to meet our regulatory obligations, although we are working hard to avoid this outcome. More information on our 2023-28 Revised Revenue Proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Bathurst, Orange and Parkes reliability project.'

2. Developments since the PADR

This section discusses the 'identified need' for this RIT-T, before outlining the key developments that have occurred since the PADR was released in February 2022. More information on the current network area is provided in Appendix B.

We note that this amended PACR does not reflect any further changes to the assumptions since the initial PACR, other than those made as a consequence of the AER's dispute determination. This is consistent with the AER's view that, as a principle, they expect Transgrid to apply the same information that was available at the time of the PACR, unless Transgrid considers that there has been a material change in circumstances as defined in the NER.

While this section remains largely the same as the corresponding section in the initial PACR, we have included additional information on the basis for the spot load forecasts below, as well as in Appendix C, to improve transparency, in-line with the AER dispute determination.

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.[16] 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.[17]

We have undertaken planning studies that show that the current central west 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. Specifically, we forecast significant under- voltage conditions in this region of our network if action is not taken.

Demand forecasts for the area have been updated since the PADR, due to both an update from Essential Energy in terms of load in their network as well as more information being provided by key spot loads in the area regarding the status of their developments. We have consequently updated the demand forecasts used in this PACR, as outlined in section 2.3.1.

The Project Specification Consultation Report (PSCR) identified thermal constraints, in addition to voltage constraints, in the area if action is not taken, particularly during times of low renewable generation dispatch in the region. The revised (lower) demand forecasts in the PADR and in this PACR (compared to the PSCR) have resulted in our updated planning studies no longer forecasting thermal constraints over the planning horizon of this RIT-T.

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

This RIT-T therefore assesses options to ensure the above NER requirements continue to be met in central west NSW in light of the forecast demand increases. We consider this a 'reliability corrective action' under

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

17 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.

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 addition, some of the credible options assessed will also affect the wholesale electricity market through the use of grid-connected storage. Both the benefits from the provision of reliable supply to Bathurst, Orange and Parkes region and wider wholesale market benefits have been estimated as part of this PACR (consistent with the earlier PADR).

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

Seven of the credible options assessed in this PACR involve the use of BESS, including five from third party proponents of these solutions, who have put forward non-network options (ie, Option 7A, Option 7B, Option 7C, Option 7D and Option 7E). These non-network BESS have been combined with later network components, in order to meet the identified need over the whole of the assessment period. Option 7A and Option 7B involve the use of BESS and network support provided through solar PV.

In addition to providing reactive support, the BESS under each of the non-network options (as well as solar PV for Option 7A and Option 7B) are also expected to be available to dispatch into the wholesale market at times, 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 provided by all options.

Two of the options considered involve grid-owned BESS (i.e., Options 5 and 6). The BESS components of these options have been sized to meet the identified need. Due to their smaller size (compared to the non-network options), the BESS components of Option 5 and Option 6 are only expected to be able to arbitrage outside of the peak demand periods in Summer and Winter, i.e., they are assumed able to arbitrage in Autumn and Spring only (as outlined in section 2.3.7 below).

These wider wholesale market 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. The wholesale market modelling remains applicable to this amended PACR and has therefore not been updated since the initial PACR (as set out in section 2.3.4 below).

While the other credible network options (i.e., the solely network options) will provide additional system strength around Parkes and/or relieve emerging line constraints around Bathurst and Orange, we do not consider there to be material wholesale market benefits associated with these options. Specifically, while providing additional system strength around Parkes and/or relieving line constraints may affect the investment decisions of future local renewable generators on the 132 kV network, upstream 330 kV network constraints outside of those considered in this RIT-T mean that any new generation is not expected to displace the output of generation elsewhere and so there are not expected to be any material wider wholesale market impacts between the options and the base case (we note also that these 330 KV constraints are expected to worsen as other renewable generators connect in the area and following completion of the Central-West Orana REZ). As a consequence, the credible options considered in this RIT-T do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market.

2.3. Developments since the PADR was released in February 2022

A number of key developments have occurred since the PADR was released, which impact the analysis in this PACR. In particular:

- demand forecasts have been updated based on additional information provided by proponents of new or expanded spot loads, as well as updated information on general load growth from Essential Energy;
- updated forecasts of when voltage limits are expected to be breached in light of the revised demand forecasts;
- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO's 2022 Integrated System Plan (ISP) and is now focused on the Step Change, Progressive Change and Hydrogen Superpower scenarios (the scenario weightings have also been updated to be consistent with the 2022 ISP);
- a number of updates to the non-network options in the PADR (Option 7A, Option 7B, Option 7C and Option 7D), including to reflect new information provided by proponents;
- inclusion of a new non-network option in the assessment (Option 7E);
- the assumptions regarding how BESS components can trade in the wholesale market have been refined; and
- there have been a number of updates to the network options, including in relation to their timing, size and cost.

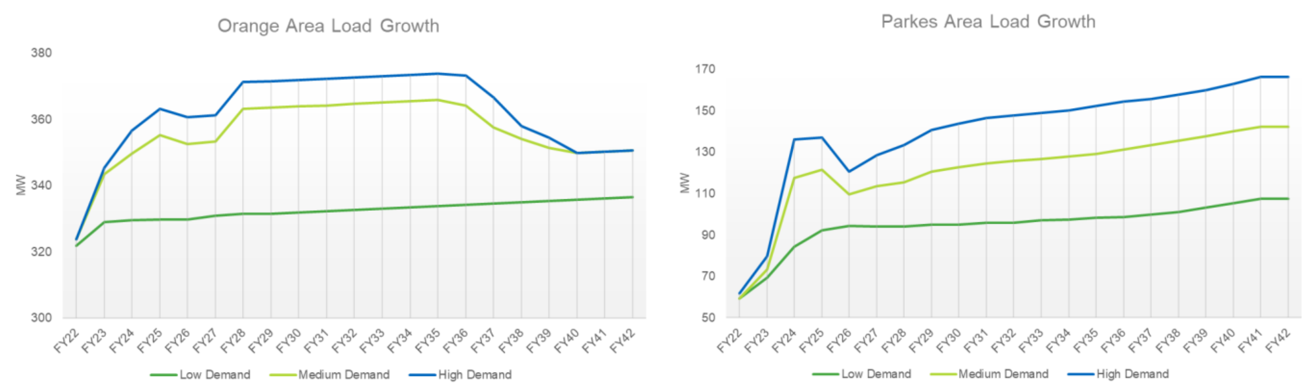
Each of these developments is discussed in the sections below.

2.3.1. Demand forecasts have been updated since the PADR

Demand forecasts are a key driver of the identified need for this RIT-T and are expected to increase significantly in the central west NSW power system due to both underlying general load growth as well as specific spot load developments coming online.

The PACR has considered three demand forecasts, representing different quantities, timings and locations for key forecast loads, as shown in Figure 2-1 below.

Figure 2-1: Peak demand forecasts for the Orange/Panorama area and the Parkes area



The demand forecasts feeding into the identified need for this RIT-T have been updated since the PADR to reflect the latest Essential Energy demand forecasts available at the time of preparing the initial PACR and updated information provided by external parties on the current state of key projects. Specifically:

- Essential Energy provided revised general demand forecasts (that have been reflected in our 2022 TAPR), which now include the demand associated with a mining load that Transgrid included in its demand forecasts for the PADR;
- Additional information provided by one of the mining loads since the PADR regarding the commitment status of an expansion they are expecting to make has led to an increased amount of load for this mine being included in the central and high demand forecasts (further increases in that mining load have been included as a sensitivity, rather than being reflected in the high scenario);
- there has been a reduction in the demand forecast of a third mining load, which has been reflected in all three demand forecasts (which was reflected in our 2022 TAPR);
- a fourth mining load has provided a revised demand forecast in response to the PADR that indicates a shorter peak demand period and reduced demand at all other times (particularly after 2025/26), which has been reflected in all three demand forecasts; and
- further discussions with the NSW government have resulted in no change being assumed for the Parkes SAP.

The demand forecasts have been developed following an extensive information gathering exercise from potential load proponents. Specifically, we asked each potential proponent to provide evidence of whether it considers the load meets the specific criteria under the RIT-T for a project to be considered ‘anticipated’ or ‘committed’.

The **low demand forecast** includes 38 MW of spot load considered ‘anticipated’, which comprises 7 per cent of the total load included in this forecast. This anticipated spot load has been included in the low forecast as we have judged this level of anticipated load to have a high enough probability of occurring, given that there are a number of anticipated spot loads in the area that may be developed. We note the anticipated spot load covers only a portion of the NSW Government’s Parkes SAP (scaled down from the central demand forecast).

The **central demand forecast** includes two additional anticipated spot loads (Sunrise Mine and McPhillamys Mine), that make up approximately 5 per cent of the total load under this forecast, as well as higher demand forecasts for a key spot load included in the low forecast (in line with the proponent’s low demand forecast). In the central forecast, the demand forecast for Parkes SAP reflects the central NSW government forecast, and makes up 9 per cent of the total load.

The **high demand forecast** includes two further additional anticipated loads that make up approximately 7 per cent of the total load under this forecast. This forecast continues to use the low forecast provided by one of the key mining spot loads. A higher forecast for Parkes SAP is included in the high demand forecast, in line with forecasts provided by the NSW government.

Appendix C provides additional detail on the various key loads and how they have been included in the assessment (while some details have had to be redacted due to confidentiality reasons, the full detail of this table has been provided to the AER in-confidence).

We also engaged GHD to independently confirm the reasonableness of the demand forecasts. GHD’s report has been published alongside this amended PACR.

The updated demand forecasts continue to be constructed to reflect the various stages of development for each key load, as well as to investigate sufficient diversity in terms of location of future spot loads to assess how the net benefit of the options considered in the PACR varies across these key assumptions.

The overall effect of the updated demand forecasts since the PADR has been a:

- reduction in demand forecasts in the Parkes area (particularly after 2025/2026), mainly due to the reduced demand forecasts for two key mine loads; and
- an increase in the demand forecasts in the Orange area, mainly due to the updated demand forecasts of one mine load.

In general, there has been a slight reduction in active power (MW) forecasts in the underlying network (and a number of notable reductions in MVAr forecasts as well). These changes have been taken these into account in our system studies for this PACR.

2.3.2. Forecast of when voltage limits are expected to be breached if action is not taken

The changes in the load forecasts have had a consequent impact on when the forecast voltage limits are expected to be breached if action is not taken under the base case.

Figure 2-2 and Figure 2-3 show the updated demand forecasts and the updated voltage limits for Orange and Parkes 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.

Figure 2-2: Updated peak demand forecast and voltage limit for the Orange/Panorama area

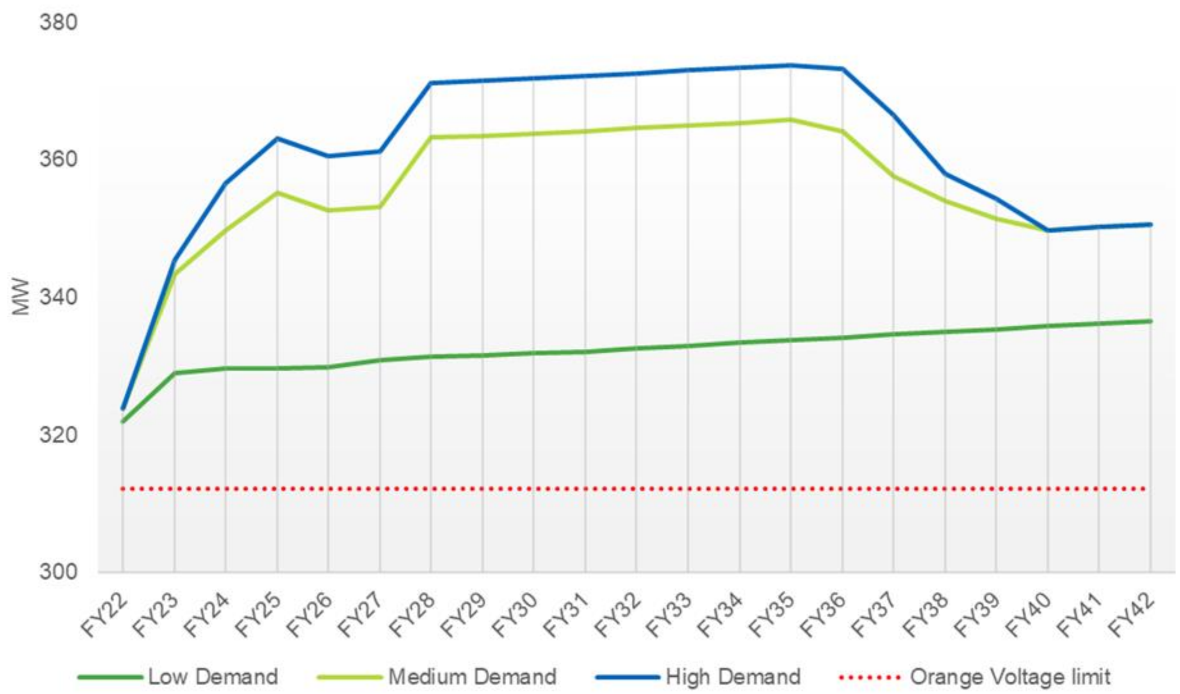
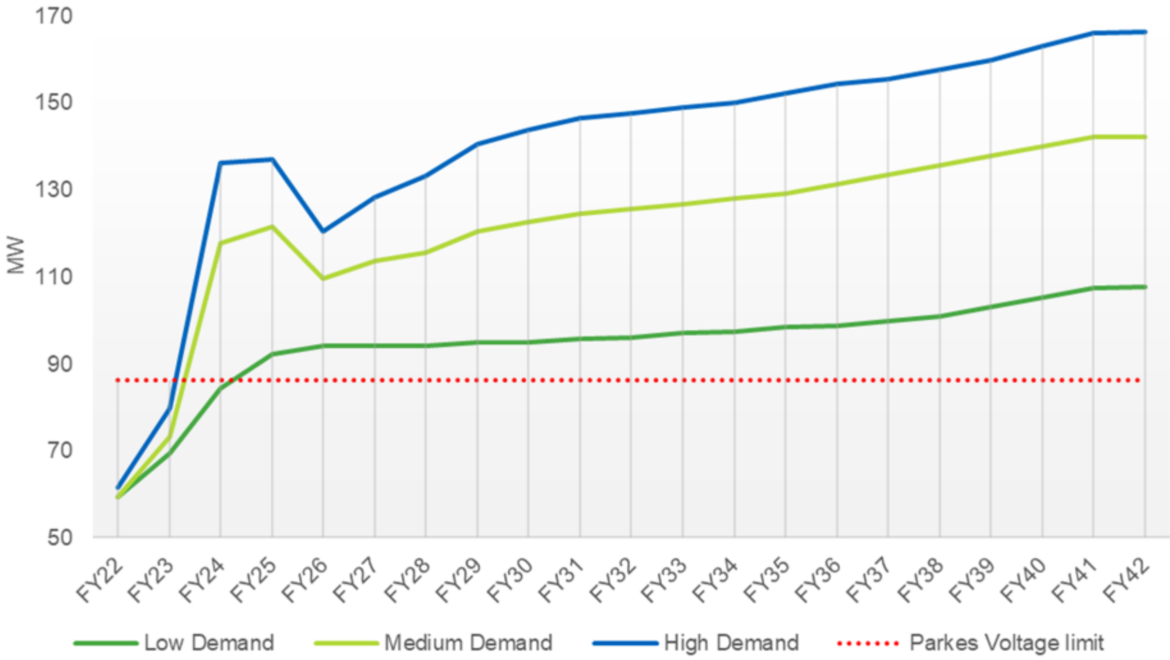


Figure 2-3: Peak demand forecast and voltage limit for the Parkes area



We have also updated our voltage limit forecasts since the PADR to reflect that the Parkes capacitor banks that the PADR assumed would be installed as part of a separate process not connected with this RIT-T are no longer being installed due to changes in the status of that separate project (they have been removed from the base case in this PACR). In calculating the limits, we have continued to assume that capacitor banks will be installed in Orange North and Panorama as part of separate Transgrid projects, required to address already committed load. The capacitor banks at Orange North and Panorama are expected to be in-service by April 2023.

2.3.3. Updated reactive power margin shortfalls if action is not taken

Our system studies also indicate that under the revised demand forecasts, the voltage constraints will result in a reactive margin shortfall around the Orange and Parkes/Panorama areas after 2023 if action is not taken. As per the requirement under Clause S5.1.8 of the NER, a minimum reactive power margin of 1 per cent of the maximum fault level has to be maintained at each location. Accordingly, the minimum reactive power margins required at the Panorama 66 kV Bulk Supply Point (BSP) and Parkes 132 kV BSP are 12.3 MVAr and 10.1 MVAr, respectively.

As shown in Table 2.1, a reactive power margin short-fall (in red) is projected at the Parkes 132 kV and Panorama 66 kV BSPs after 2024, under (N-1) contingency conditions (for the medium demand forecast).

Table 2.1: Projected reactive power margin at the Parkes 132 kV and Panorama 66 kV Bulk Supply Points (medium demand forecast)

Bulk Supply Point	Contingency	Required min Q Margin as per NER (MVAr)	Q Margin in 2023 (MVAr)	Q Margin in 2024 (MVAr)	Q Margin in 2025 (MVAr)	Q Margin in 2030 (MVAr)
Panorama 66 kV	TL 94X	12.3	31.8	10.0	0.9	4.6
Parkes 132 kV	TL 94K	10.1	12.9	-60.6	-72.5	-68.7

While we project that there will be reactive margin shortfalls if nothing is done, these are considered a secondary concern to the forecast voltage constraints. Specifically, the voltage constraints are expected to be the first and most material constraint to be reached and, once resolved, will fully resolve the reactive power margin shortfall as well.

2.3.4. The wholesale market modelling has been updated from the PADR to explicitly model the three key 2022 ISP scenarios

The credible options in the PADR were assessed using a set of market modelling assumptions that were largely based on the 'Progressive Change' scenario identified by AEMO in the draft 2022 ISP (released in December 2021).

The wholesale market modelling has now been updated in the PACR to:

- explicitly model each of the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 ISP, adopting the 2021 IASR assumptions; and
- align with the optimal development path and assumptions in the draft 2022 ISP.

The wholesale market modelling has not been updated since the initial PACR, consistent with the direction from the AER. Specifically, the AER has advised that in amending the PACR we are to apply the same information that was available at the time of the PACR, unless we consider that there has been a material change in circumstances (as defined in the NER). We do not consider that the limited differences in the optimal development path and assumptions between the draft and final 2022 ISPs are sufficient enough to materially affect the wholesale market benefits for this RIT-T (and we note that wholesale market benefits are relatively small for the options considered, making up only between zero and 12 per cent of the gross market benefits for the options assessed).

Section 6.3 provides further detail on how the market modelling has been undertaken for this PACR, while Appendix F provides an overview of the market simulation exercise undertaken and the key assumptions drawn upon. A separate market modelling report prepared by EY was released alongside the initial PACR, and remains relevant to this amended PACR.

We note that there were two announcements made between the draft 2022 ISP and the initial PACR regarding the early closure of coal-fired power stations in the NEM. Specifically:

- AGL announced in February 2022 that the Loy Yang A Power Station in Victoria and Bayswater Power Station in NSW will close by at least 2045 and 2033, respectively (three years early than previously indicated);[18] and
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring Power Station in August 2025 (seven years early than previously indicated).[19]

The wholesale market modelling included as part of this PACR (and the initial PACR) takes account of these dates (and draws directly on the latest AEMO generator information database available at the time of the initial PACR).

We note that on 29 September 2022, AGL updated its expected closure date for the Loy Yang A Power Station to the end of the 2035 financial year (up to 10 years earlier than previously planned).[20] However, we do not consider this announcement to be material to the overall assessment due to the market modelling retiring power stations according to least-system-cost, as opposed to at set dates,[21] and the significance of the wholesale market benefits in the overall assessment.[22]

2.3.5. Updates to the non-network options (Options 7A-D)

We have worked with the proponents of the non-network solutions (Option 7A, Option 7B, Option 7C and Option 7D) to review the proposed timing and cost of each solution. This has resulted in the following changes since the PADR:

- timing updates for Options 7A, 7B and 7C:
  - Options 7A and 7B have been pushed back by one to two years; and
- minor revisions to the costs of Options 7C and 7D:
  - the Parkes solution under Option 7C has decreased in cost due to it being clarified with the proponent that two network synchronous condensers would be used instead of a non-network BESS, while the Panorama BESS has slightly increased in cost; and
  - Option 7D has increased in cost due to a revised solution that replaces synchronous condensers with STATCOMs.
- elements of the non-network options being resized and re-scoped:
  - the Parkes solution under Option 7C has a revised solution due to it being clarified with the proponent that two network synchronous condensers would be used instead of a non-network BESS at Parkes;
  - Option 7D has a revised solution that replaces synchronous condensers with STATCOMs; and
  - Option 7D's Parkes BESS and Panorama BESS have increased in rated energy capacity, in light of the revised demand forecasts since the PADR.

Since the PADR, we also conducted an assessment of the technical capacity of all non-network options assessed in the PACR (including Option 7E, outlined below) and now consider that the non-network

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18 AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4.

19 Origin Energy, *Media release - Origin proposes to accelerate exit from coal-fired generation*, 17 February 2022, at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

20 AGL Energy, *A clear pathway for a responsible energy transition,* p. 1. See: https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/how-we-source-energy/loy-yang-power-station/220930-ly-transition.pdf

21 Specifically, the wholesale market modelling forecasts that Loy Yang A will be retired ahead of 2035 in the Step Change and Hydrogen Superpower scenarios. While the modelling finds that Loy Yang A continues its operation until the early 2040s under the Progressive Change scenario, we do not consider this material to the overall assessment given it relates to one generator, under one scenario (with a weight of 30 per cent), and the wholesale market benefits only make up a small proportion of the total estimated net benefits (see next footnote).

22 Specifically, the wholesale market benefits are relatively small for the options considered, making up only between zero and 12 per cent of the gross market benefits for the options assessed.

options will be able to address the load growth's voltage constraints sufficiently until the network is strengthened by the Wellington to Parkes 132 kV line.

The capital costs in this amended PACR remain the same as in the initial PACR. We have however presented a sensitivity with increased costs for the network component of the options, to reflect our latest unit rates, in line with our revised Regulatory Proposal.

2.3.6. A new non-network option has been included in the assessment (Option 7E)

In response to a submission made in response to the PADR, a new non-network option has been included in the PACR analysis, 'Option 7E'.

Option 7E uses BESS to provide a network support service in combination with a network synchronous condenser. The details of Option 7E have not been presented in this PACR to preserve the requested confidentiality by the proponent.

As with the other non-network options, this option is not considered to be a long-term standalone solution and, instead, will defer or avoid some of the network investment that would otherwise be required. Further information regarding Option 7E is provided in section 4.7.

2.3.7. Updated assumptions regarding how BESS components can trade in market services

We have further assessed the ability of BESS components to use their capacity to participate in market services outside of their network support commitments. This covers the five non-network-provided BESS options (i.e., Options 7A, 7B, 7C, 7D and 7E) as well the two network-owned BESS options (i.e., Options 5 and 6).

While the PADR adopted a simplifying assumption that BESS components could use their full capacity to participate in the market,[23] we now assume that all options can only use their full capacity to participate in market services during Autumn and Spring, and a limited capacity during Summer (mid-November to mid-March) and Winter. Specifically, over Summer and Winter, it is assumed that:

- after the commissioning of non-network components at Parkes:
  - no battery capacity is available
- after the commissioning of non-network components at Panorama:
  - no battery capacity is available for Options 5, 6, 7B, 7D and 7E; and
  - a portion of the battery capacity is required to be reserved, with the remainder available for Options 7A and 7C.

These assumptions reflect best estimates at this point in time, and the specific commercial and operational requirements for BESS components of non-network options will be refined during the commercial negotiations and procurement process following the completion of the RIT-T.

[23] This assumption was made at the time of the PADR as a simplifying assumption, and one in favour of the non-network options, in order to test whether these options were expected to be preferred. The PADR outlined that we would be working with proponents to revise this assumption ahead of the PACR (see section 6.4 of the PADR).

2.3.8. Updates to the network options

We have reviewed and, in some cases, updated the timing and size of the network components of each credible option in light of the updated demand forecasts. This has resulted in the size of components at Parkes being reduced substantially, with components at Panorama being increased slightly.

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects.

In addition, as outlined above, following a more detailed review of the BESS components' ability to arbitrage outside of their network support commitments, the network owned BESS options (Option 5 and Option 6) are now assumed to only be able to arbitrage during Autumn and Spring (and not in Summer or Winter), which refines the broad assumption in the PADR that they could use their full capacity to arbitrage. [24]

[24] Consistent with the current transmission ring-fencing guidelines, we have implicitly assumed that we would lease out the spare battery capacity to a third party to provide these contestable services. However, we note that the AER is currently reviewing the transmission ring-fencing guidelines and, specifically, in the case of TNSP-owned batteries, whether the TNSPs should be able to lease excess capacity to third parties. The AER's draft transmission ringfencing guidelines propose not to permit TNSPs to lease spare battery capacity, unless they have obtained a waiver from the AER (see: AER, *Electricity Transmission Ring-fencing Guideline*, Explanatory Statement – Version 4, Draft, p. viii). However this position is currently being consulted on. The ability of this option to generate these wider wholesale market benefits is therefore subject to the outcome of this review process.

3. Consultation on the PADR

The PADR was released in February 2022 and we subsequently received submissions from eleven parties.

Submissions from PIAC, the Central New South Wales Joint Organisation (CNSWJO) and the Parkes Shire Council are publicly available and have been published on our website.[25] The remainder of the submitters explicitly requested confidentiality and so the details of these submissions have not been included in this PACR, or on our website.

The main topics that emerged in the submissions were:

- a new non-network option;
- further details regarding earlier proposed non-network options;
- uncertainty around the demand forecasts;
- the appropriateness of the use of non-network options to address voltage constraints;
- estimating the market benefits, including use of the ISP scenarios, weighting of the scenarios and inclusion of additional benefits; and
- proposed modifications to the network options.

The key matters raised in the public submissions are summarised in the following subsections, together with our responses and how the matters raised have been reflected in the PACR assessment. Appendix G provides a summary of all public points raised as part of consultation on the PADR.

3.1. Uncertainty around the demand forecasts

Local government stakeholders expressed concern that growth assumptions in the PADR for the eastern part of the region for both industry and population are underestimated, and that energy security may be compromised.[26] On the other hand, PIAC expressed concern that demand forecasts based on regional growth plans may not be met, and recommended any projected demand relating to regional growth plans should be based on an independent assessment that takes into account the actual approved and/or financially committed developments.[27]

In preparing this PACR, we have engaged further with load proponents on the commitment status for key potential loads. Specifically, we have liaised directly with each proponent to determine whether the loads are considered 'committed'/ 'anticipated' under the RIT-T, i.e., whether they meet the criteria for these classifications under the RIT-T. Appendix C provides additional detail on the various key loads and how they have been included in the assessment (while some details have had to be redacted due to confidentiality reasons), in response to the AER's dispute determination.

PIAC expressed concerns over demand forecasts being treated as commercial-in-confidence.[28]

We understand that there are valid commercial reasons for demand forecasts being kept confidential in RIT-T processes. While not released publicly, the detail regarding all load forecasts has been shared in-

25 https://www.transgrid.com.au/projects-innovation/bathurst-orange-and-parkes-supply
26 CNSWJO, pp 1-2, 10-11.
27 PIAC, p 1.
28 PIAC, p. 1.

confidence with the AER in its role of overseeing the RIT-T and ensuring the efficiency of any ultimately proposed expenditure.

The CNSWJO, whose submission was supported by Parkes Shire Council, observed that the PSCR referenced particular mine loads and specific load forecasts for Parkes SAP, whereas these were not specifically mentioned in the PADR.[29]

We note that the only two mining loads that were mentioned by name in the PSCR and PADR were the McPhillamy's gold mine and the CleanTeQ Sunrise Nickel-Cobalt-Scandium mine (both of which are public) and the that the names, locations and loads of all other mines were redacted due to confidentiality reasons. The PSCR also only presented a high-level load forecast range for the Parkes SAP (not specific load forecasts as suggested), while the PADR simply commented on the how its modelled load had changed since the PSCR.

3.2. The appropriateness of the use of non-network options to address voltage constraints

The CNSWJO emphasised the importance of energy security for the region and suggested that the revision of the credible options from the PSCR to the PADR had focussed on facilitating the REZ at the expense of broader energy security.[30]

The change in credible options between the PSCR and the PADR reflected both submissions to the PSCR and EOI (resulting in four new options being included that utilise non-network technologies put forward by third-party proponents) as well as revised demand forecasts since the PSCR (which led to the network elements being resized and rescoped). The revision in the credible options since the PSCR (either as part of the PADR or this PACR) has not involved a consideration of REZ connections as suggested by the CNSWJO. All options in the PADR, and now PACR, are considered able to meet the identified need, driven by the demand forecasts, as outlined in section 4.

The CNSWJO observed that the PADR refers to only voltage constraints (not thermal constraints) and does not detail whether the constraint is voltage above ten per cent nominal or voltage below ten per cent nominal under foreseeable conditions.[31]

While the PSCR identified thermal constraints in the area if action is not taken, particularly during times of low renewable generation dispatch in the region, demand forecasts reduced prior to publishing the PADR and our updated planning studies drawn upon for this PACR no longer forecast thermal constraints over the planning horizon of this initial RIT-T. The voltage constraints are due to under-voltage, which has now been made clearer in the PACR.

3.3. Estimating the market benefits

The CNSWJO argued that the wholesale market modelling should be updated to reflect AEMO's Step Change scenario given the development of environmental and geopolitical factors around the world.[32]

We initially modelled the market benefits for the PADR using AEMO's 'steady progress' 2022 ISP scenario, which AEMO noted in the 2021 IASR is 'similar conceptually to the 2020 central scenario'. However, the

[29] CNSWJO, p 6 and Parkes Shire Council, p 1.
[30] CNSWJO, p 3.
[31] CNSWJO, p 6.
[32] CNSWJO, pp 7-8.

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 the PADR over December 2021 and January 2022 to be based on the Progressive Change scenario (time would not permit updating to the Step Change scenario).

The market modelling for the PACR has been updated to explicitly model each of the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 ISP, adopting the 2021 IASR assumptions (see section 2.3.4).

PIAC recommended applying 50 per cent weighting to each of the central and low net economic benefits scenarios (and removing the high benefits scenario).[33]

We note that the purpose of using a high benefits (and low benefits) scenario is to test the rankings of options against an extreme bound of plausible economic benefits. Specifically, the three scenarios assessed in the initial PACR reflect combinations of assumptions that are expected to affect the ranking of the credible options, including the expected wholesale market benefits, in order to comprehensively test the range of net benefits that can be expected from the credible options.

We note that the high benefits and low benefits scenarios were largely symmetric in terms of the assumptions drawn upon and we consider that removing one (as PIAC suggested) would bias the analysis.

In light of the AER dispute determination, we have amended how the scenarios are constructed and in this amended PACR we now assess the options across three scenarios consistent with the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR. Section 5.1 outlines how the scenarios have been updated from the initial PACR.

The CNSWJO argued that particular non-network options should be favoured over others given their potential to create jobs in the region.[34] While we note these expected real sources of benefit, they are not able to be captured in the RIT-T analysis due to it being a cost-benefit assessment focussed on 'all those who produce, consume and transport electricity in the market' and the benefits like job creation are considered 'externalities' under the RIT-T.

3.4. Proposed modifications to the options

A range of variants to building a direct 132 kV line from Wellington to Parkes were proposed by CNSWJO including alternate routes, building a dual circuit line, and building the line at 330 kV. These variants are suggested to offer capacity, voltage and reliability benefits to the Central West network and Parkes region. The CNSWJO argued that extending the 330 kV network would offer significant advantages beyond the Bathurst, Orange and Parkes region.[35]

Our Project Development team has assessed each of the variants proposed by CNSWJO and concluded that they are expected to be significantly more expensive than the preferred network options assessed in this PACR (Option 3) due to the additional easements and biodiversity offset costs required. Moreover, it is not expected that these variants would provide commensurately greater market benefits to offset these costs and so they have not been considered as credible options in this PACR.

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[33] PIAC, p 2.
[34] CNSWJO, p 10.
[35] CNSWJO, p 10.

Parkes Shire Council proposed that potential synergy with the Neoen wind farm at Alectown should be considered in the analysis.[36]

We have considered this possibility and concluded that the Alectown wind farm would be unlikely to contribute to addressing the identified need in the short term. In addition, EY have used the latest AEMO generation information list at the time that the analysis was conducted (from May 2022) in conducting the wholesale market modelling for this PACR, which does not include the Alectown wind farm as a committed or anticipated generator.

[36] Parkes Shire Council, p 1.

4. Credible options assessed

The credible options considered in the PACR assessment have been refined since the PADR, to reflect:

- Option 5 and Option 6 (grid-owned BESS) only being expected to be able to arbitrage outside of the peak demand periods in Summer and Winter;
- slightly resized componentry due to the revised load forecasts; and
- the Parkes capacitor banks being removed from the background assumptions due to changes in the status of that separate project.

We have commented on where options have been refined since the PADR in each of the sections below.

The credible network options assessed in this PACR differ in the near-term by where, how and when new capacity is added to the central west network going forward. Specifically, the network options differ by:

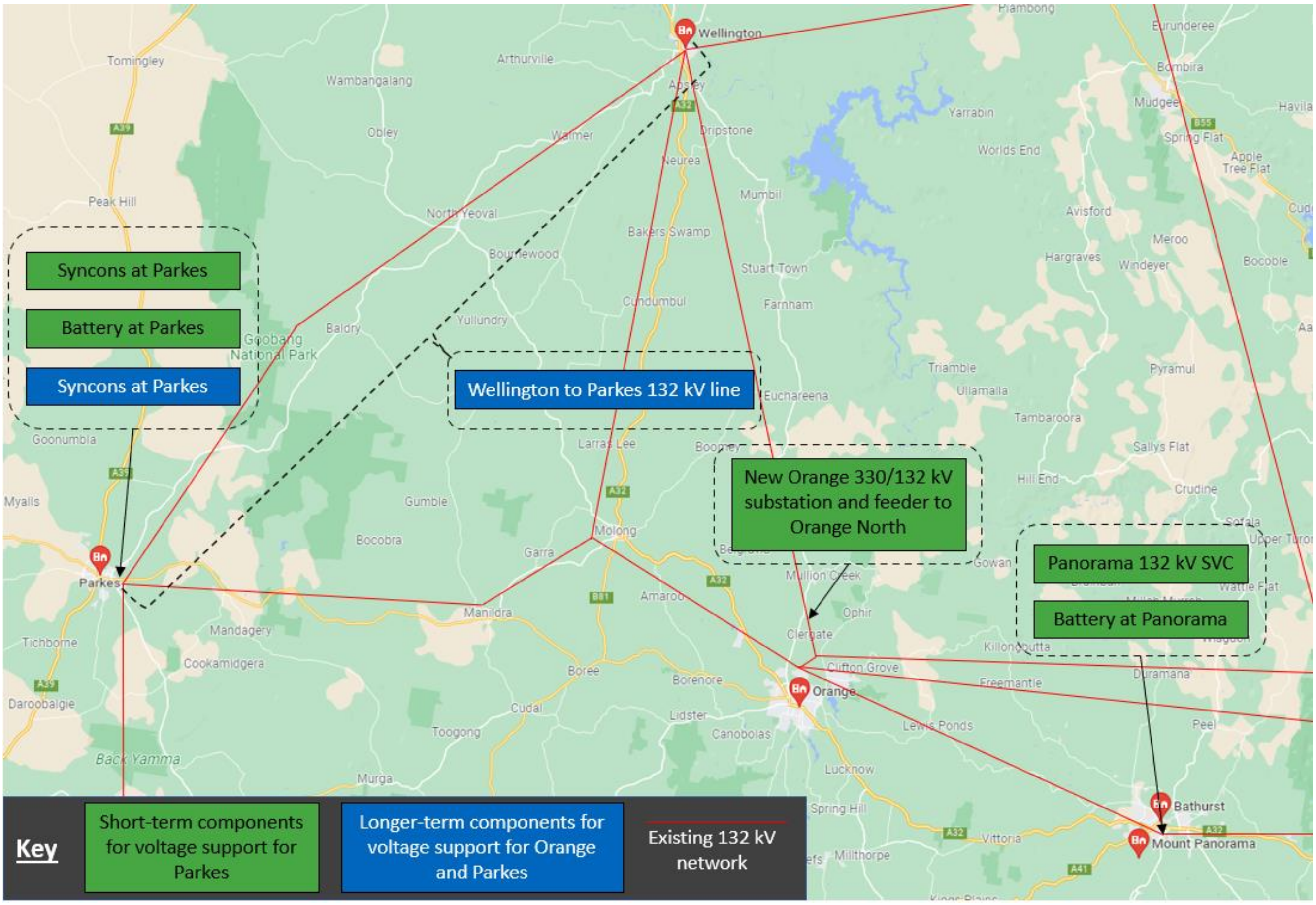
- how reactive support is provided in the short-term (including through traditional transmission network elements as well as through installing dynamic reactive power devices);
- how much reactive support is provided in the short-term; and
- whether a new transmission line is ultimately built over the longer-term.

Figure 4-1 below illustrates the various components that form the credible network options considered. 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.

Importantly, each of the options involves two broad potential stages of investment, depending on the option and scenario. These are shown in the figure below as the short-term components required for voltage support for Parkes (in green) and the longer-term components required for voltage support for Orange and Parkes (in blue). The individual option sections below detail the specific timing assumed for each stage of each option under the two demand forecasts.

Figure 4-1: Various components the credible network options involve



While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a 'longer-term' component for the options, we note that it is required in 2027/28 for Option 1A/1B under the central and high demand forecasts (but is not required under the low demand forecast).

As outlined in section 4.7, each of the five non-network solutions has been modelled in terms of its ability to efficiently defer or avoid the short-term reactive support requirements at Panorama and/or Parkes for the preferred network option (i.e., Option 3).

Table 4.1 below summarises each of the credible options assessed in the PACR. All options are considered to meet the identified need from a technical, commercial, and project delivery perspective.[37]

While all potential components of each option are shown in Table 4.1, the later components 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) and the high demand forecast. The timing of the initial components for all options has been fixed across the three 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 components varies by demand 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 component of each option under the three demand forecasts.

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

While many of the options involve a new Wellington to Parkes 132 kV line, we currently consider that the lowest cost approach to building this new line is to rebuild the existing single circuit line as a double circuit line on the existing easement (and so the costing for the line is based on this scope). This represents a brownfield development and is in line with Transgrid's preference to maintain social licence by utilising existing easements where possible.

While some component costs in Table 4.1 below include land costs and biodiversity offset costs, they have not been broken out separately to contain the table. However, the NPV model released alongside the PACR separates out these elements.

Table 4.1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)		
1A/1B[38]	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Wellington to Parkes 132 kV line	• $123 million[39]
Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)		
1C	• Initial synchronous condenser at Parkes 132 kV (25 MVA)	• $28 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Second synchronous condenser at Parkes 132 kV (25 MVA)	• $26 million
	• Third synchronous condensers at Parkes 132 kV (35 MVA)	• $32 million
Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)		
3	• Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 x 25 MVA)	• $84 million
	• Wellington to Parkes 132 kV line	• $121 million
Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
4	• Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 x 25 MVA)	• $84 million
	• New Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (35 MVA)	• $27 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)		

[38] In the PSCR this option distinguished between Option 1A and 1B because of the then anticipated future stages of developments. These later stages are no longer considered necessary and so these two options have been collapsed into one option. The option naming has been retained in the PADR and in this PACR for consistency.

[39] Please note that the estimated cost of the Wellington to Parkes line is slightly higher for Option 1A/1B than it is for Option 3, Option 5, Option 7A, Option 7B, Option 7C, Option 7D and Option 7E since, for Option 1A/B, the new Wellington-Parkes line connection is the first work undertaken at Parkes and so it includes the scope to add 132 kV bus section circuit breakers (which is included in the earlier stages of Option 3, Option 5, Option 7A, Option 7B, Option 7C, Option 7D and Option 7E).

Option	Description	Estimated capex ($2020/21)
5	• 25 MVAr synchronous condensers at Parkes + 20 MW (40 MWh) BESS at Parkes + 25 MW (50 MWh) BESS at Panorama	• $140 million
	• Wellington to Parkes 132 kV line	• $121 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
6	• 25 MVAr synchronous condensers at Parkes + 20 MW (40 MWh) BESS at Parkes + 25 MW (50 MWh) BESS at Panorama	• $140 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (35 MVA)	• $27 million
Combination of non-network solutions with the top-ranked network option (Option 3)		
7A	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7B	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7C	• Synchronous condenser at Parkes 132 kV (2 x 25 MVA) • BESS at Panorama • Wellington to Parkes 132 kV line	• $55 million for the synchronous condensers • Confidential for the non-network components • $121 million for the line
7D	• BESS and STATCOM at Parkes • BESS and STATCOM at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components (including the STATCOMs) • $121 million for the line
7E	• BESS at Parkes • BESS at Panorama • 25 MVAr synchronous condenser at Parkes • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $41 million for the synchronous condensers • $121 million for the line

The synchronous condensers at Parkes under Option 7C and Option 7E are network components.

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. Appendix D provides additional detail on the methodology used to estimate capital costs (consistent with the AER dispute determination), including biodiversity offset and land costs.

All network options are assumed to have annual operating and maintenance costs equal to approximately one per cent of their capital costs (excluding biodiversity offset and land costs).

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 1A/1B – New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)

Option 1A/1B involves constructing:

- a new 330/132 kV substation near Orange initially (including two transformers and a 132kV line to the existing Orange North substation); and
- a new Wellington to Parkes 132 kV line, if required.

Table 4.2 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.2: Summary of the assumed timing for each component of Option 1A/1B across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	2027/28	2027/28	2027/28
Wellington to Parkes 132 kV line	NA	2028/29	2028/29

The establishment of a new Orange 330/132 kV substation involves:[40]

- a cut-in to Line 72 (Wellington to Mt Piper 330 kV);
- a cut-in to Line 947 (Orange North to Wellington Tee Burrendong)
- two new 330/132 kV transformers (375 MVA);
- a new 132 kV Line to existing Orange North substation; and
- a new 132 kV bay (and a circuit breaker) at the existing Orange North 132 kV substation.

Figure 4-2 below illustrates the type and location of the key elements for Option 1A/1B.[41] While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a ‘longer-term’ component for other options, we note that it is commissioned in 2028/29 for this option under the central and high forecasts (but is not required under the low forecast).

[40] This work is the same for all options that involve this component.

[41] While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a ‘longer-term’ component for other options, we note that it is required in 2027/28 for this option under the central and high forecasts.

Figure 4-2: Overview of the key elements in Option 1A/1B

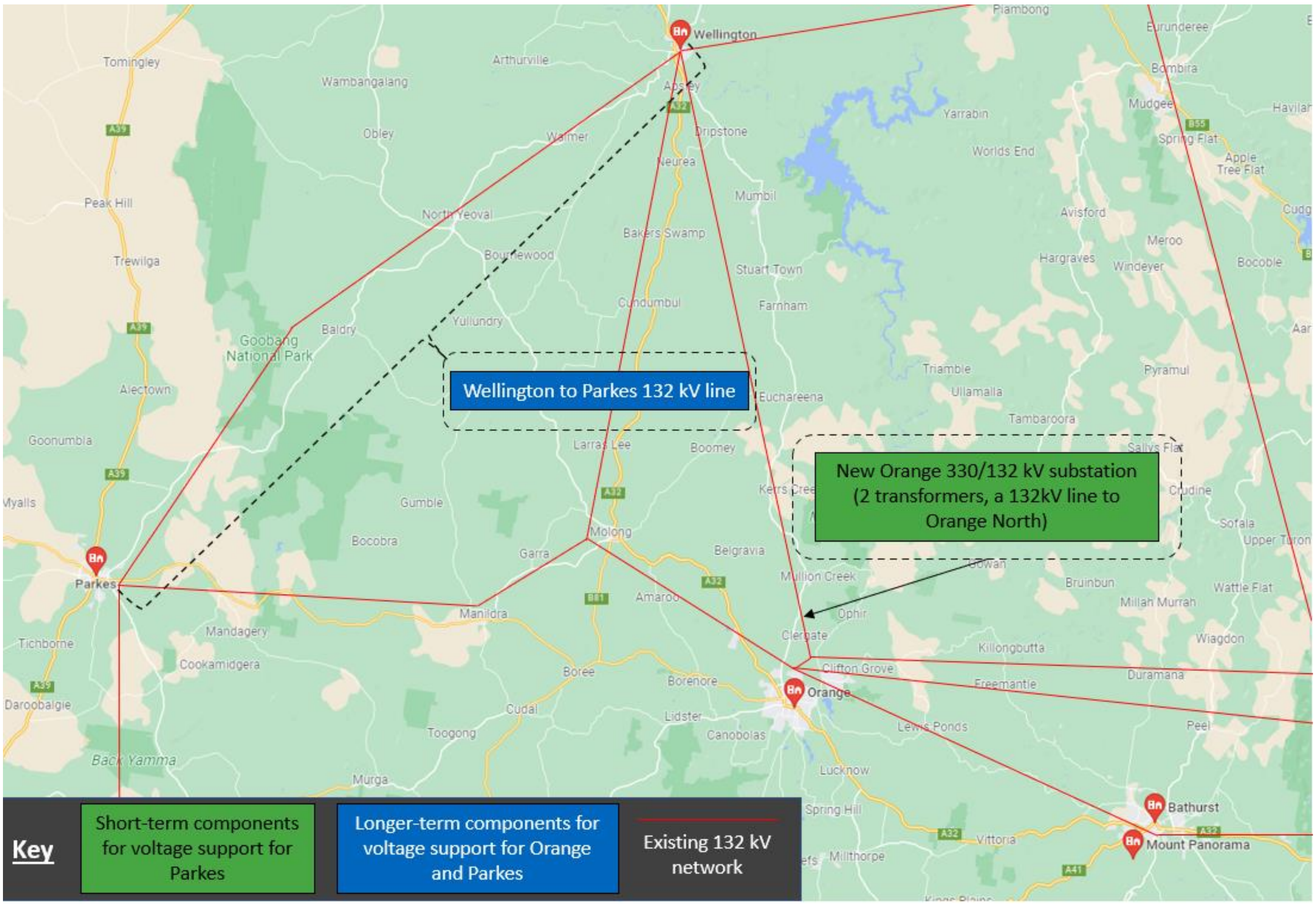


Table 4.3 summarises the expected construction time for each component.

Table 4.3: Summary of the expected construction time for each component of Option 1A/1B

Component	Expected construction time
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
Wellington to Parkes 132 kV line	64 months

4.2. Option 1C – Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)

Option 1C involves constructing:

- an initial synchronous condenser at Parkes 132 kV (25 MVA);
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation);
- a second synchronous condenser at Parkes 132 kV (25 MVA), if required; and
- a third synchronous condenser at Parkes 132 kV (35 MVA), if required.

The extent of the works for the new 330/132 kV substation at Orange are the same as set out under Option 1A/1B.

Table 4.4 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.4: Summary of the assumed timing for each component of Option 1C across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Initial synchronous condenser at Parkes 132 kV (25 MVA)	2026/27	2026/27	2026/27
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	2035/36	2027/28	2027/28
Second synchronous condenser at Parkes 132 kV (25 MVA)	NA	2031/32	2027/28
A third synchronous condenser at Parkes 132 kV (35 MVA)	NA	NA	2033/34

Figure 4-3 below illustrates the type and location of the key elements for Option 1C.

Figure 4-3: Overview of the key elements in Option 1C

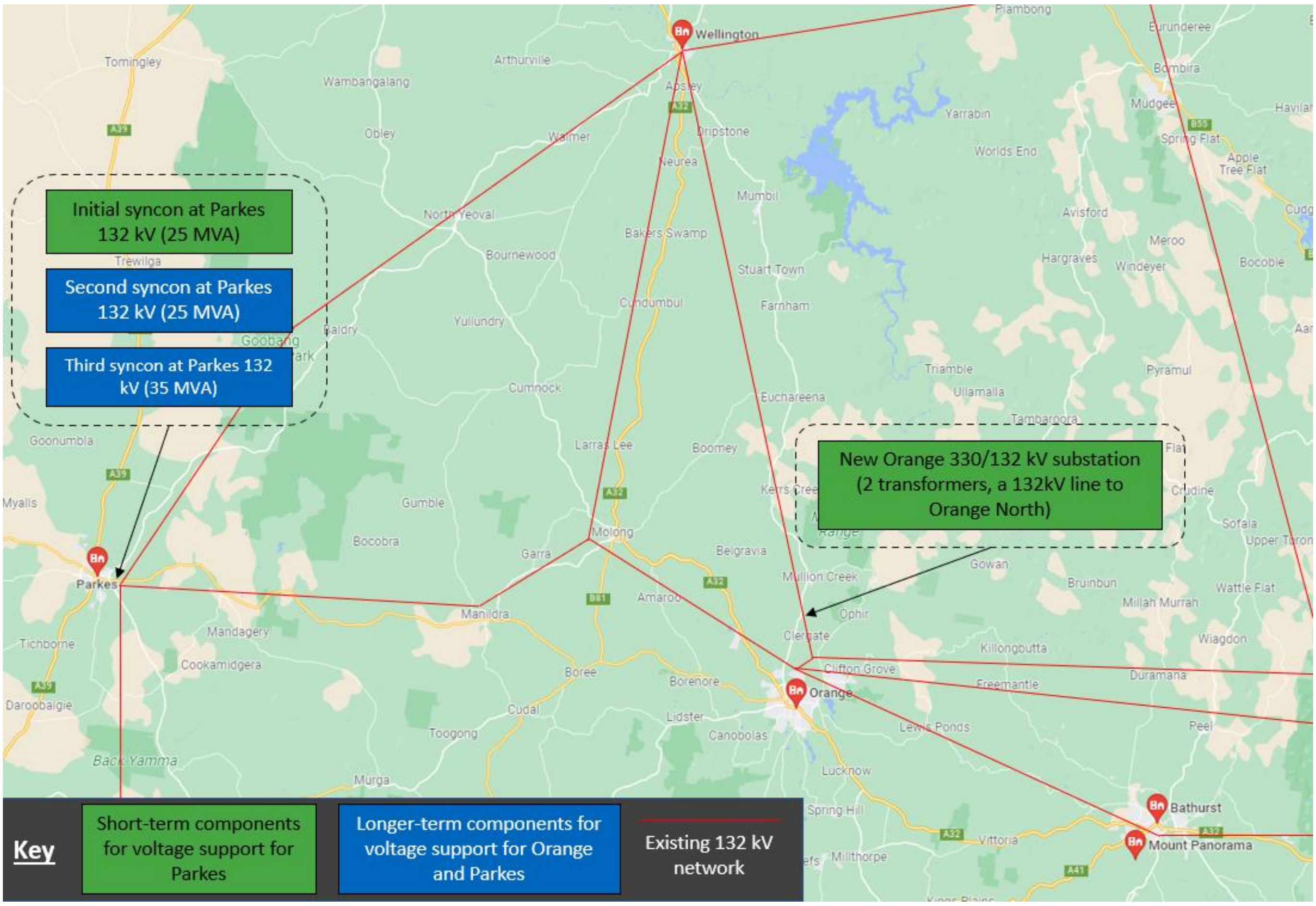


Table 4.5 summarises the expected construction time for each component.

Table 4.5: Summary of the expected construction time for each component of Option 1C

Component	Expected construction time
Initial synchronous condenser at Parkes 132 kV (25 MVA)	40 months
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
Second synchronous condenser at Parkes 132 kV (25 MVA)	40 months
A third synchronous condenser at Parkes 132 kV (35 MVA)	40 months

4.3. Option 3 – Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)

Option 3 involves constructing:

- Panorama 132 kV SVC (30 MVA)[42] and two synchronous condensers at Parkes 132 kV (2 × 25 MVA); and
- a new Wellington to Parkes 132 kV line, if required.

Table 4.6 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.6: Summary of the assumed timing for each component of Option 3 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 × 25 MVA)	2026/27	2026/27	2026/27
Wellington to Parkes 132 kV line	NA	2031/32	2028/29

A key benefit of Option 3 (and the other options involving dynamic reactive support upfront (i.e., Option 1C, Option 4, Option 5 and Option 6)) is that they are able to be commissioned a year earlier than Option 1A/1B and so avoid additional unserved energy. However, Option 1C involves constructing a synchronous condenser in 2026/27 that is expected to avoid most, but not all, of the unserved energy in that year.

Figure 4-4 below illustrates the type and location of the key elements for Option 3.

42 Since the PSCR, we have considered SVCs, synchronous condensers and STATCOMs for this component and now assume an SVC since it has been found to be the lowest cost of the three choices (with the other two not expected to provide any additional benefits).

Figure 4-4: Overview of the key elements in Option 3

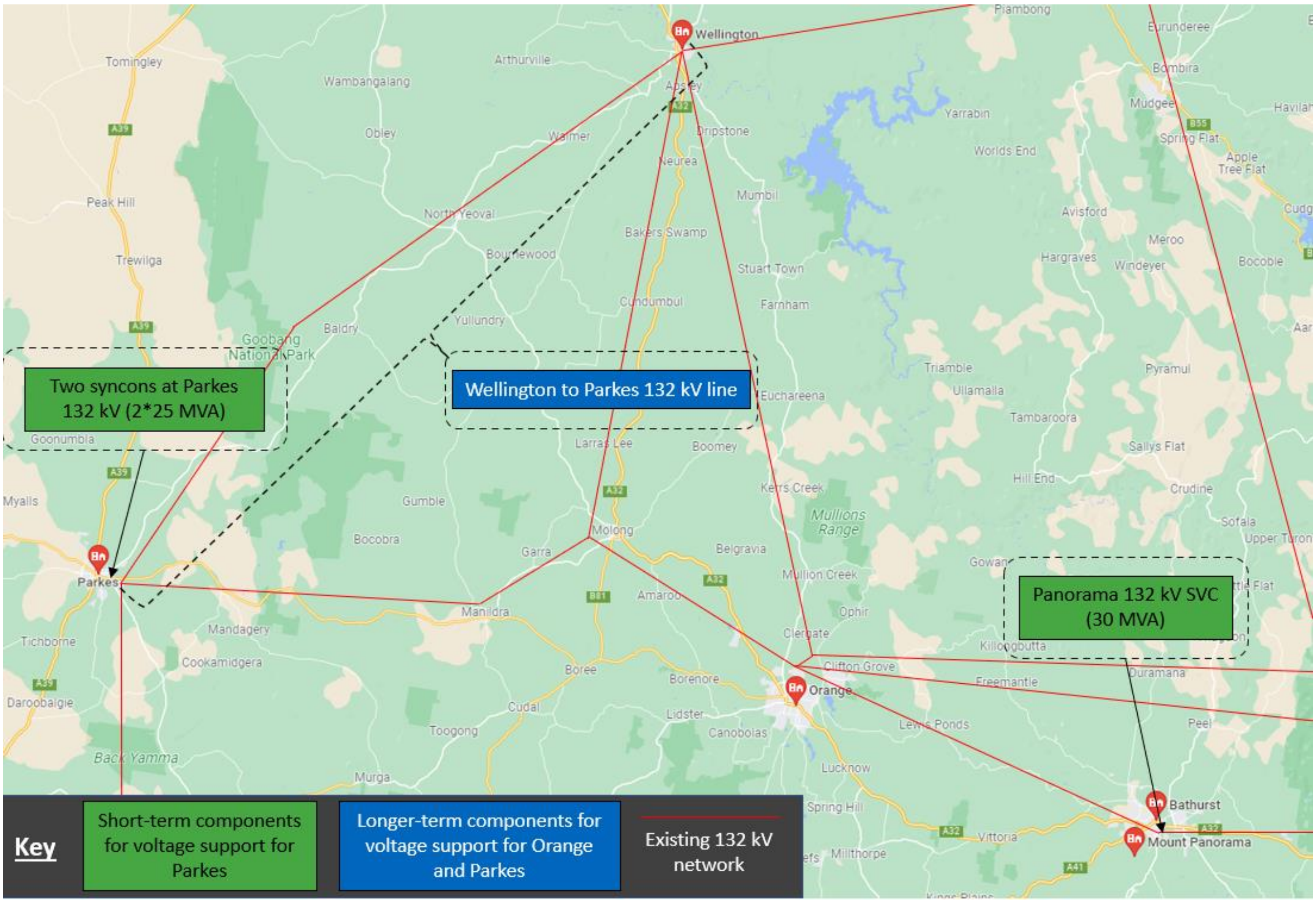


Table 4.7 summarises the expected construction time for each component.

Table 4.7: Summary of the expected construction time for each component of Option 3

Component	Expected construction time
Panorama 132 kV SVC (30 MVA) + synchronous condenser at Parkes 132 kV (2 × 25 MVA)	42 months
Wellington to Parkes 132 kV line	64 months

4.4. Option 4 – Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

Option 4 involves constructing:

- Panorama 132 kV SVC (30 MVA)[43] and two synchronous condensers at Parkes 132 kV (2 × 25 MVA);
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation); and
- a third synchronous condenser at Parkes 132 kV (35 MVA), if required.

[43] Since the PSCR, we have considered SVCs, synchronous condensers and STATCOMs for this component and now assume an SVC since it has been found to be the lowest cost of the three choices (with the other two not expected to provide any additional benefits).

Table 4.8 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.8: Summary of the assumed timing for each component of Option 4 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Panorama 132 kV SVC (30 MVA) and two synchronous condensers at Parkes 132 kV (2 × 25 MVA)	2026/27	2026/27	2026/27
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	NA	2031/32	2027/28
A third synchronous condenser at Parkes 132 kV (35 MVA)	NA	NA	2032/33

Figure 4-5 below illustrates the type and location of the key elements for Option 4.

Figure 4-5: Overview of the key elements in Option 4

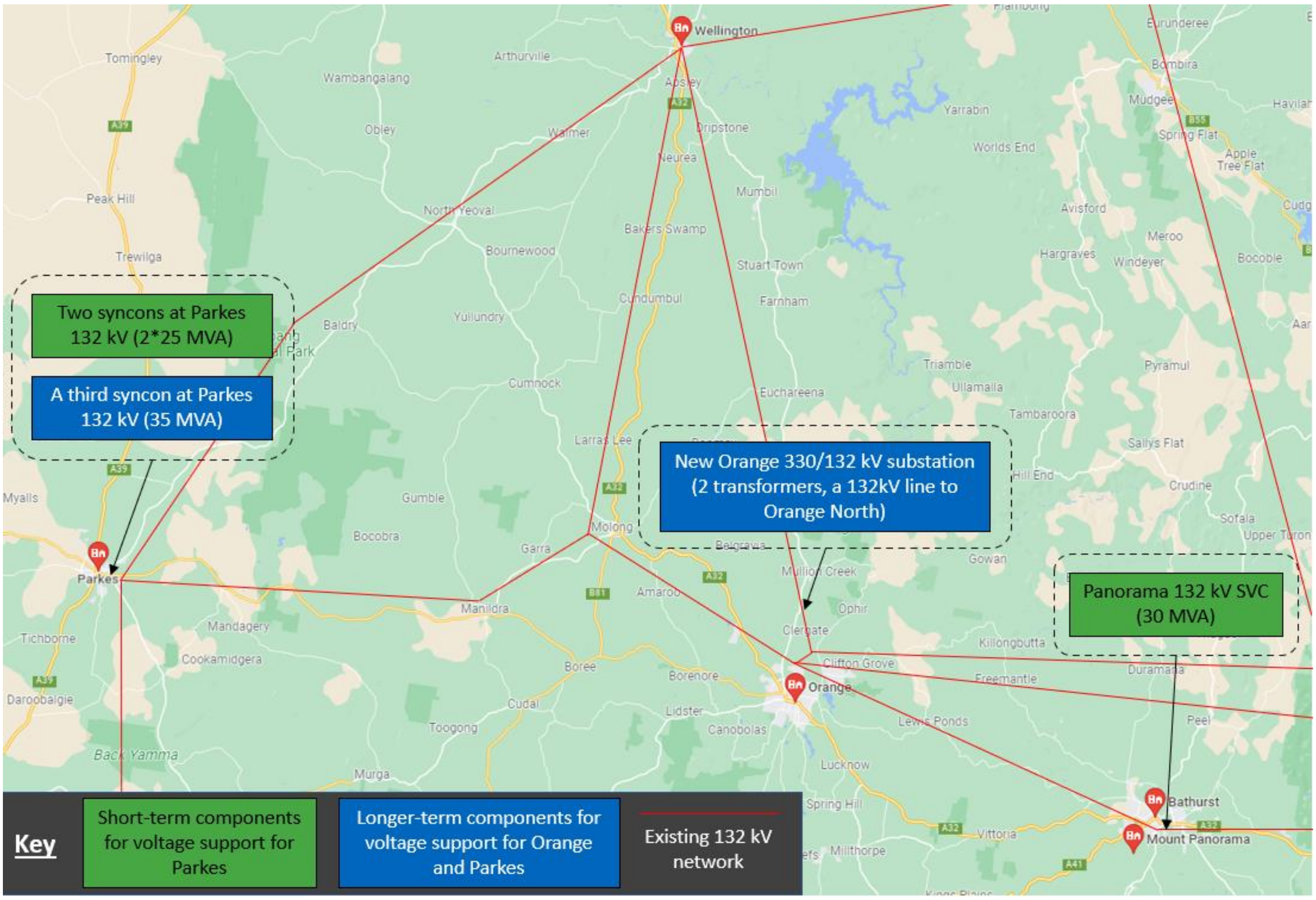


Table 4.9 summarises the expected construction time for each component.

Table 4.9: Summary of the expected construction time for each component of Option 4

Component	Expected construction time
Panorama 132 kV SVC (30 MVA) and two synchronous condensers at Parkes 132 kV (2 × 25 MVA)	42 months
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
A third synchronous condenser at Parkes 132 kV (35 MVA)	40 months

4.5. Option 5 – BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)

Option 5 involves constructing:

- 25 MVAr synchronous condensers at Parkes, a 20 MW (40 MWh) battery at Parkes and a 25 MW (50 MWh) battery at Panorama; and
- a new Wellington to Parkes 132 kV line, if required.

Batteries can generally be used for a number of grid support services. In this option (and in Option 6), it is expected that the batteries will output both active and reactive power. At times of high renewable generation and low demand in the area, the batteries can be charged and then can be discharged at times of high demand and low renewable generation. The batteries can also provide MVAr output to provide dynamic reactive support, particularly during system disturbances.

As outlined in section 2.3.8, Option 5 (and Option 6) have been updated since the PADR to reflect that they are now only expected to be able to arbitrage outside of the peak demand periods in Summer and Winter.

Table 4.10 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.10: Summary of the assumed timing for each component of Option 5 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
25 MVAr synchronous condenser at Parkes, a 20 MW (40 MWh) battery at Parkes and a 25 MW (50 MWh) battery at Panorama	2026/27	2026/27	2026/27
Wellington to Parkes 132 kV line	NA	2031/32	2028/29

Figure 4-6 below illustrates the type and location of the key elements for Option 5.

Figure 4-6: Overview of the key elements in Option 5

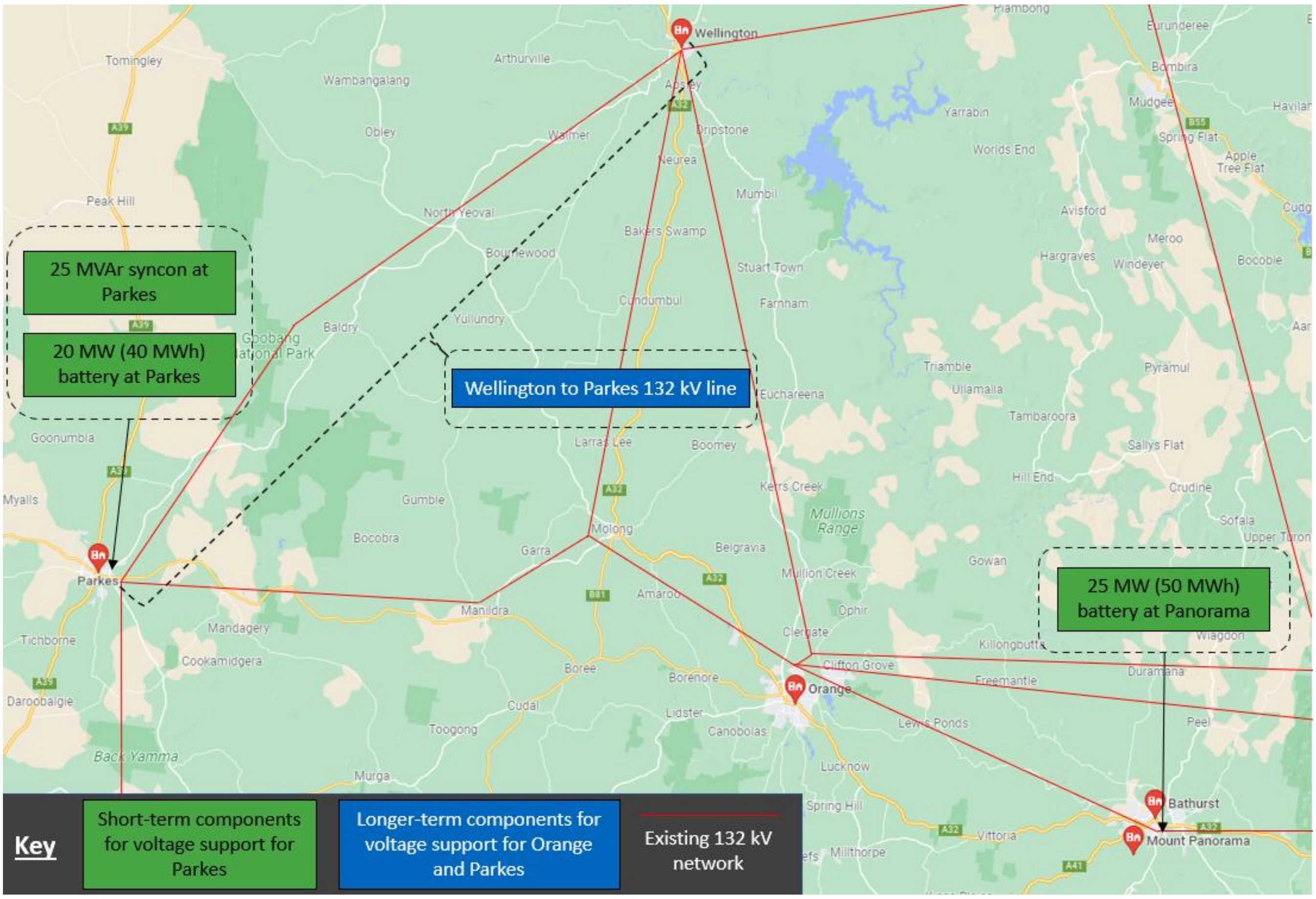


Table 4.11 summarises the expected construction time for each component.

Table 4.11: Summary of the expected construction time for each component of Option 5

Component	Expected construction time
25 MVAr synchronous condenser at Parkes + 20 MW (40 MWh) battery at Parkes + 25 MW (50 MWh) battery at Panorama	42 months
Wellington to Parkes 132 kV line	64 months

4.6. Option 6 – BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

Option 6 involves constructing:

- 25 MVAr synchronous condenser at Parkes, a 20 MW (40 MWh) battery at Parkes and a 25 MW (50 MWh) battery at Panorama;
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation); and
- a second synchronous condenser at Parkes 132 kV (35 MVA), if required.

As with Option 5, Option 6 assumes a network-owned battery (i.e., as distinct from the non-network options outlined below) and the cost of the BESS has been updated since the PADR to reflect a proposal from a proponent in response to the PADR.

Table 4.12 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4.12: Summary of the assumed timing for each component of Option 6 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
25 MVAr synchronous condenser at Parkes, a 20 MW (40 MWh) battery at Parkes and a 25 MW (50 MWh) battery at Panorama	2026/27	2026/27	2026/27
New 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation)	NA	2031/32	2027/28
Second synchronous condenser at Parkes 132 kV (35 MVA)	NA	NA	2032/33

Figure 4-7 below illustrates the type and location of the key elements for Option 6.

Figure 4-7: Overview of the key elements in Option 6

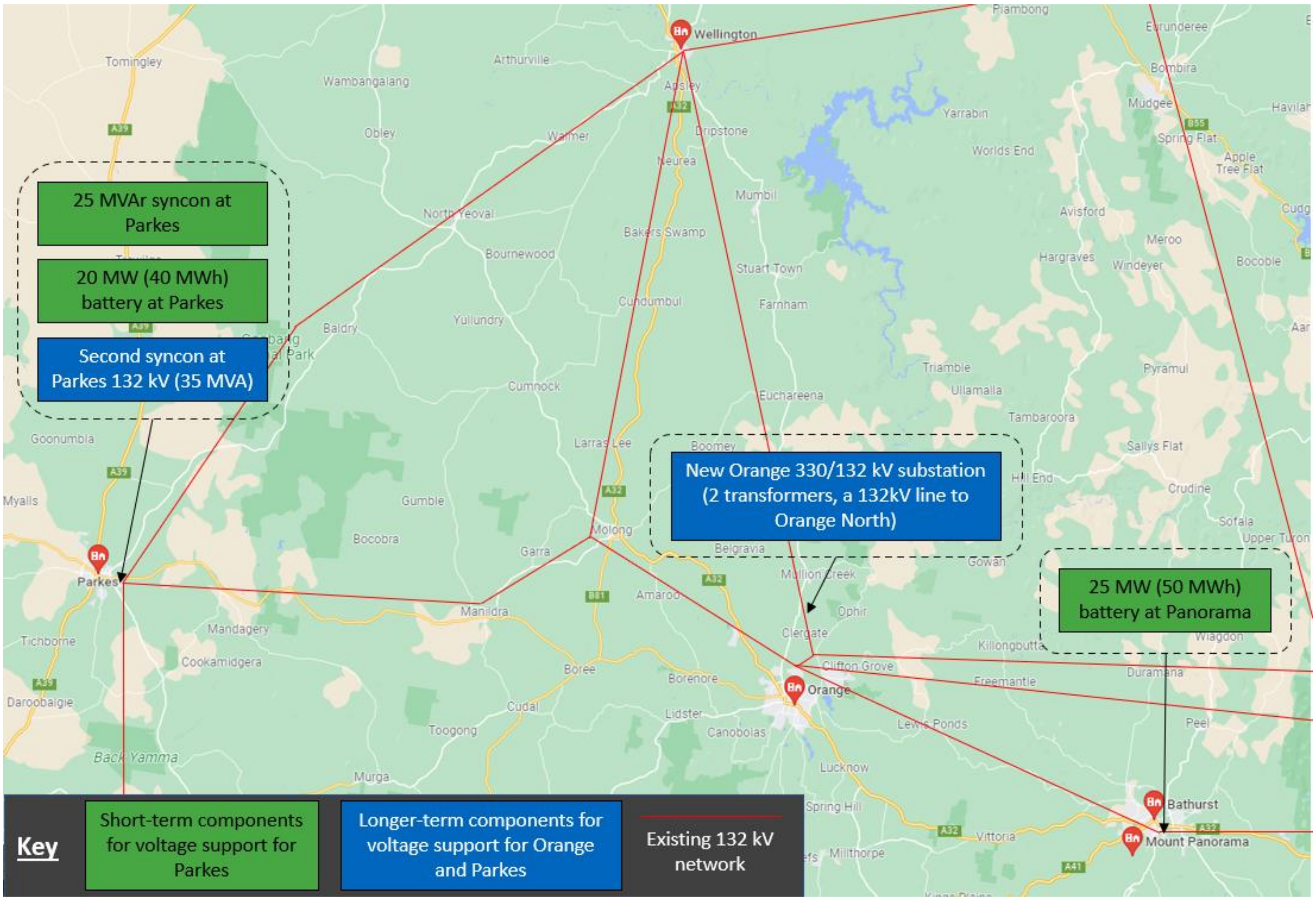


Table 4.13 summarises the expected construction time for each component.

Table 4.13: Summary of the expected construction time for each component of Option 6

Component	Expected construction time
25 MVAr synchronous condensers at Parkes, a 20 MW (40 MWh) battery at Parkes and a 25 MW (50 MWh) battery at Panorama	42 months
New 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation)	59 months
Second synchronous condenser at Parkes 132 kV (35 MVA)	40 months

4.7. Option 7 – Non-network options

The non-network options use a combination of technologies to provide reactive support at Panorama and Parkes. In particular, Option 7A and Option 7B use BESS in combination with solar PV, Option 7C and Option 7E use BESS in combination with a synchronous condenser, while Option 7D uses BESS in combination with STATCOMs. We have not presented the complete detail regarding these options in order to preserve the confidentiality requested by proponents.

We have assessed the technical feasibility of these options further since the PADR and consider, at this stage, that they are technically feasible and are able to address the identified need in a timely manner. We note that the connection process following the RIT-T will further assess and confirm the specific technical details of connection for the preferred option.

Table 4.14 specifies the minimum dynamic reactive power support requirements for non-network options that Transgrid will seek from proponents. Several parties have proposed larger solutions that provide other market services, in addition to providing this network support service.

Table 4.14: Minimum dynamic reactive power requirements for non-network options

Year	Parkes 132 kV	Panorama 132 kV
2023	-	10 MVAr
2024	45 MVAr	25 MVAr
2025	50 MVAr	30 MVAr
2030	50 MVAr	30 MVAr

Table 4.15 summarises the optimal assumed timing for these options under the three different demand forecasts investigated.

Table 4.15: Summary of the assumed timing for the components of Options 7A-7E

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Non-network components	Confidential	Confidential	Confidential
Wellington to Parkes 132 kV line	NA	2031/32	2028/29

The timing assumed at this stage for each of the non-network options has been based on the submissions received from, and follow-up clarifications with, proponents.

The non-network solutions are not considered to be long-term standalone solutions and, instead, provide alternate ways to provide reactive support at Panorama and/or Parkes for the preferred network option

(Option 3). We consider this represents a proportionate approach to considering these solutions for this RIT-T.

4.8. 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 4.16.

Table 4.16: Options considered but not progressed

Option	Reason(s) for not progressing
A range of variants to building a direct 132 kV line from Wellington to Parkes were proposed by CNSWJO in their submission to the PADR including alternate routes, building a dual circuit line, and building the line at 330 kV.	We have assessed each of the variants proposed by CNSWJO and concluded that they are expected to be significantly more expensive than the preferred network options assessed in this PACR (Option 3) due to the additional easements and biodiversity offset costs required. Moreover, it is not expected that these variants would provide commensurately greater market benefits to offset these costs and so they have not been considered as credible options in this PACR.
Capacitor banks/ switched capacitors	Not technically feasible. Due to the expected extensive load growth in the Parkes and Orange areas, adding a number of additional capacitor banks or switched capacitors in the area is considered to be a non-credible solution (even in light of the reduced demand forecasts since the PSCR). There are number of capacitor banks already in-service at Parkes, Orange and Panorama substations and further capacitor banks are shortly to be commissioned as part of separate Transgrid projects to address load growth in the medium-term. Installing further additional capacitor banks will lead to voltage control/regulation stability issues.
Constructing a new 330 kV line between Orange and Parkes (Option 2 from the PSCR).	Not commercially feasible. This option from the PSCR is no longer considered commercially feasible in light of the updated demand forecasts. It is expected to cost at least 60 per cent more than Option 3 and is not expected to provide any greater level of market benefit.

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.

The construction of the scenarios and scope of the sensitivity testing has been a key amendment to the PACR following the AER dispute determination.

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.[44] 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 PACR assessment, which differ in terms of the key drivers of the estimated net market benefits. The scenarios in this amended PACR have been updated in-line with the AER dispute determination and align with the 2021 IASR.

Specifically, the three scenarios now reflect the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR. They also vary by local spot load forecast and new local renewable generation assumptions, which are not parameters included in the ISP but which can be expected to have a material impact on the options considered in this RIT-T. We have aligned the higher local spot load forecast and higher new local generation assumptions with the ISP scenarios that reflect higher economic growth, so that the scenarios are internally consistent. The scenarios no longer vary the assumed network or non-network capital costs, the VCR or discount rate. This approach has been discussed and agreed with the AER following their dispute determination.

We have varied the local spot load forecasts across scenarios, although it is a departure from the scenarios included in the 2021 IASR, because:

- the identified need for this RIT-T is a localised issue; and

44 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.

- local spot load forecasts are a key driver of the identified need, and are expected to have a material impact on the outcome of this RIT-T.

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered. It also shows where there has been a change in an assumption from the initial PACR following the AER dispute determination (where the initial assumption is shown italicised in parentheses).

Table 5.1: Summary of scenarios (and changes since the initial PACR)

Variable	Step Change	Progressive Change	Hydrogen Superpower
Network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Non-network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Demand	Central demand forecast (as outlined in section 2.3.1)	Low demand forecast (as outlined in section 2.3.1)	High demand forecast (as outlined in section 2.3.1)
New renewable generation in the area[45]	In-service generators from Appendix B.	In-service generators from Appendix B. *(All in-service and commissioning generators))*	All in-service and advanced generators from Appendix B. *(In-service, commissioning, and advanced generators)*
Wholesale market benefits estimated	EY estimated based on the Step Change 2022 ISP scenario	EY estimated based on the Progressive Change 2022 ISP scenario	EY estimated based on the Hydrogen Superpower 2022 ISP scenario
VCR	$54.54/kWh	$54.54/kWh *($38.18/kWh)*	$54.54/kWh *($70.91/kWh)*
Discount rate	5.50%	5.50% *(7.50%)*	5.50% *(1.96%)*

While there are changes to the assumed level of new renewable generation in two of the scenarios above (as a result of aligning these assumptions with the underlying economic growth assumptions for those IASR scenarios to ensure they are 'internally consistent'), we note that in practice this has had no effect on the analysis (and, in particular, the estimates of when the constraints may bind and the amount of unserved energy expected).[46]

45 Please note that this table no longer refers to 'committed' generators as there are no longer any for the area, as outlined in Appendix B.

46 Specifically, the only difference between these two sets of assumptions is the treatment of 'advanced' generators, which for this RIT-T are predominantly solar farms. Solar generation timing during a day does not align with the time of day that the peak demand occurs and therefore the solar generation has an immaterial impact on unserved energy. The output of wind farms such as Flyers Creek Wind Farm provide on average 30% of their installed capacity, which also has an immaterial impact on unserved energy.

While wholesale market benefits are relevant to this RIT-T, we note that they are only one element that is expected to affect the ranking of the credible options and only affect the net benefits of six of the eleven options (i.e., those involving BESS, as outlined in section 2.2).

5.2. Weighting the reasonable scenarios

We have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. Specifically, we have given each scenario a weighting based on the proportion its weighting in the 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios, i.e.:[47]

- 52 per cent to the Step Change scenario;
- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

These weights are the same as those used in the initial PACR, although we note that the underlying basis for the scenarios (and consequently the scenario parameters) has been updated in line with the AER dispute determination. The weights differ from those used in the PADR,[48] reflecting the fact that the wholesale market benefits have now been estimated across the three 2022 ISP scenarios, whereas the PADR only estimated wholesale market benefits for the Progressive Change scenario (as outlined in section 2.3.4).

While the above weights have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7), we have also carefully considered the results in each scenario in section 7. In addition, we have undertaken a sensitivity using alternative weightings (see section 7.5.6).

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 sensitivity tests has been expanded from the initial PACR in-line with the AER dispute determination.

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

- a higher demand forecast for a key mining load;
- the VCR;
- different commercial discount rates;
- capital costs for both network and non-network options;
- the impact of different spot load forecasts;
- scenario weightings; and
- the assumed timing of both the network and non-network components

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

47 We note also that these weights align with the weights AEMO have recommended be applied to the VNI West RIT-T (where the same three scenarios are to be considered) in the draft 2022 ISP released in December 2021 – see: AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 69.

48 The PADR weighted the central scenario at 50 per cent (given it is considered the most likely since it is based primarily on a set of expected assumptions), with the other two scenarios being weighted equally with 25 per cent each.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The sensitivity testing also includes ‘boundary testing’, where relevant, to investigate what key variables would need to change by in order to change the identified preferred option.

6. Estimating the market benefits

As outlined in section 2, the key benefit expected from the options is avoided involuntary load shedding in central west NSW. In addition, for options that involve non-network components, 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 NEM outcomes expected in each case, and includes the location and quantity of load in central west NSW, 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 PACR assessment. Appendix F provides additional detail on the wholesale market modelling undertaken by EY. We also published a separate modelling report prepared by EY alongside the initial PACR 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 PACR 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 Orange and Parkes areas are 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 2027/28 as part of the PADR analysis since each option will address all constraints equally from then on and so avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2027/28 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, if the full amounts are captured, they will dwarf the other quantified costs and benefits (e.g., we estimate that these will exceed $400 million/year by 2028/29 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 2027/28. 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[49] and advice provided to the AER.[50]

6.2. Avoided involuntary load shedding in central west NSW

We have run system studies to estimate the Expected Unserved Energy (EUE) in central west NSW under each of the three 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.[51] Specifically, we have developed a load-weighted VCR estimate of $54.54/kWh using the AER VCR values for the customer groups relevant to the region as shown in the table below.

Table 6.1: Load weighted VCR breakdown ($2021)

	Residential	Commercial	Industrial	VCR estimate
AER VCR estimate[52]	$26.8/kWh	$46.2/kWh	$66.2/kWh	$54.54
BOP load breakdown	21%	16%	63%	

We have also applied VCR estimates that are 30 per cent lower and 30 per cent higher as part of our sensitivity testing, consistent with the AER's specified +/- 30 per cent confidence interval.[53]

The EY market modelling has also quantified the impact of changes in involuntary load shedding *outside* of central west NSW 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 central west NSW for each option. However, these estimated changes in EUE are not expected to be material for any of the credible options.

6.3. Wholesale market benefits

As outlined in section 2.2, seven of the credible options assessed in this PACR involve the use of BESS, two of which also involve solar PV (Option 7A and Option 7B), that are expected to be able to dispatch to the wholesale market in addition to providing short term reactive support. 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.[54]

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. Appendix F summarises the key variables under the three scenarios modelled 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.

49 ENA, *RIT-T Economic Assessment Handbook for non-ISP RIT-Ts*, Version 2.0, 26 October 2020, p. 51.
50 Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.
51 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.
52 See AER, *Annual update – VCR review final decision – Appendices A to E – December 2021*.
53 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.
54 While the other credible network options (i.e., the solely network options) will provide additional system strength around Parkes and/or relieve emerging line constraints around Bathurst and Orange, we do not consider there to be material wholesale market benefits associated with these options as outlined in section 2.2.

Table 6.2 below summarises the specific categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR.

Table 6.2: Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR

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 non-network components have been captured in the PACR 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.[55] 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 PACR 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	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

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

Market benefit	Overview
load curtailment (outside of central west NSW)	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.
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 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.

6.4. General modelling parameters adopted

The RIT-T analysis spans a 20-year assessment period from 2022/23 to 2041/42. This period is the same as the initial PACR and begins and ends a year later than the PADR and reflects the passage of time since that document was released.

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.

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 amended PACR, consistent with the assumptions adopted in the 2021 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 2.30 per cent, [56] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[57]).

6.5. 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.[58]

56 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23..

57 AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.

58 NER clause 5.16.1(c)(6).

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 central west NSW 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 being considered are sufficiently flexible to respond to that change. The credible options outlined in this PACR exhibit flexibility in terms of how they can be developed and we have captured the option value of this flexibility implicitly 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.

The options are also not expected to have a material impact on ancillary services costs in the NEM. Specifically, each of the options have been designed to resolve the voltage issues on the network and so solve the expected FCAS issues in an identical manner. The options that involve BESS components are not expected to be able to sell services into the FCAS market (given they will be resolving the voltage issues).

7. Net present value results

This section outlines the results of the economic assessment we have undertaken of the credible options. Specifically, it applies the amended scenario assumptions (summarised in section 5.1) and presents an expanded set of sensitivities (as summarised in section 5.3).

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 7A, Option 7B, Option 7C, Option 7D and Option 7E (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The market modelling report prepared by EY accompanying the initial PACR provides additional detail in terms of the modelled wholesale market impacts for each option, which remains relevant for this amended PACR. Neither this PACR nor the EY 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. The full analysis has been provided in-confidence to the AER as part of their role in overseeing the RIT-T.

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. Step Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Step Change' scenario from the 2021 IASR. It also assumes the central demand forecasts (outlined in section 2.3.1) and the in-service renewable generators from Appendix B.

Under these assumptions, two of the options involving non-network solutions in the short-term (i.e., Option 7D and Option 7E) are preferred over the solely network options and other non-network options. They are strongly preferred over the network options 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.

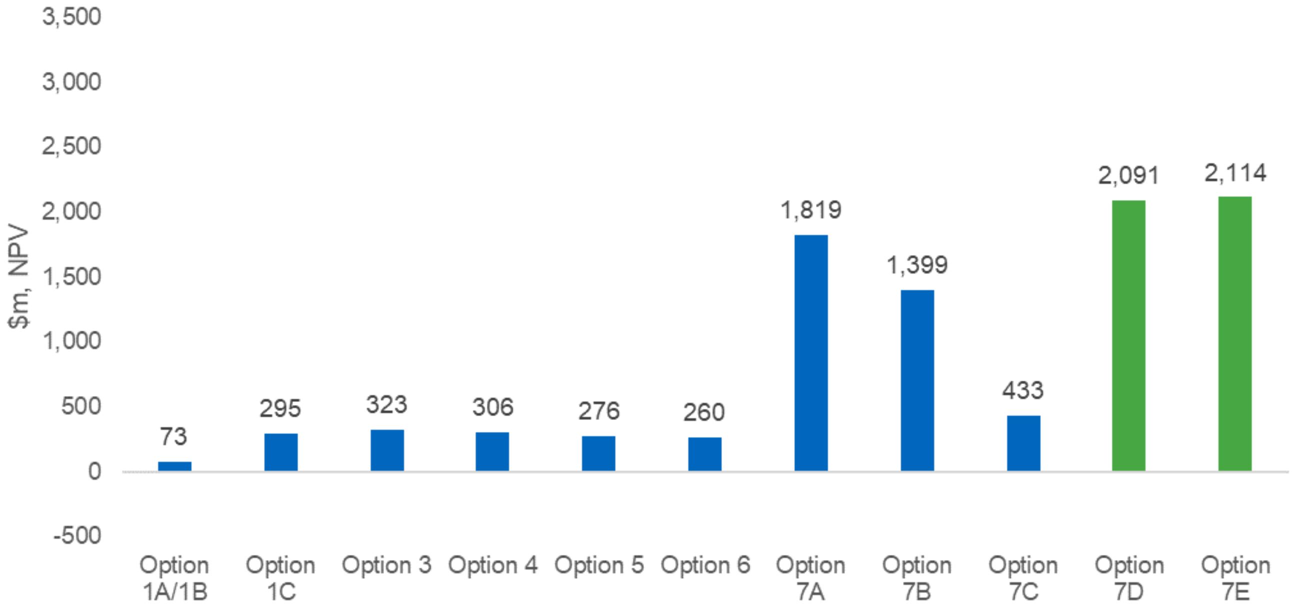
Option 7E is the top-ranked option overall, with estimated net benefits that are approximately $23 million (1 per cent) greater than Option 7D and $1,792 million (555 per cent) greater than the preferred network option (Option 3).[59]

The other three non-network options, Options 7A-7C, are also found to have net market benefits that are significantly greater than Option 3 (by between $111 million and $1,497 million).

Figure 7-1 shows the overall estimated net benefit for each option under the Step Change scenario. All figures of this format in the PACR show the top-ranked option(s) in green, and the other options in blue.

[59] Please note that while this sentence, and all sentences of this type in the PACR, presents the percentage differences between options, these percentages are calculated excluding the avoided expected unserved energy after 2027/28 as it is common to all options (and so does not assist in identifying the preferred option), as outlined in section 6.1. These percentages should therefore be interpreted as being based on net benefit numbers that exclude the superfluous unserved energy, as opposed to being based on the *total* expected net benefit numbers.

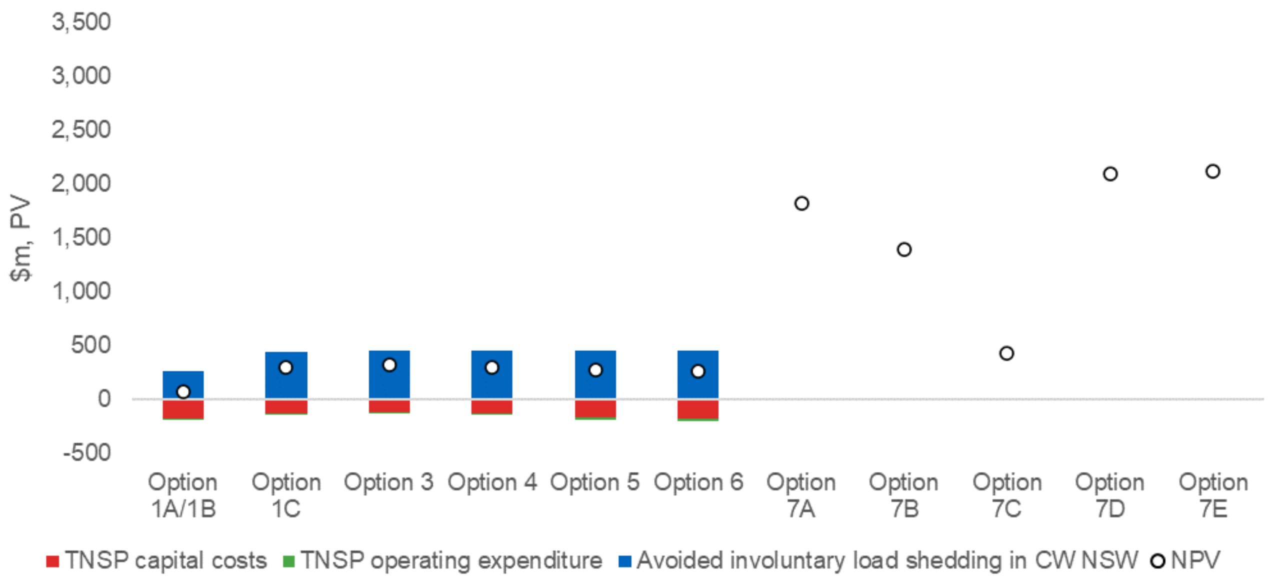
Figure 7-1: Summary of the estimated net benefits under the Step Change scenario



The ranking of the non-network options has changed since the PADR, where all non-network options were found to be effectively ranked equally, reflecting a more granular approach to estimating avoided unserved energy in the year the BESS components are commissioned as well updated (later) assumed timing for Option 7A and Option 7B. In addition, the Parkes solution under Option 7C has been revised due to it being clarified with the proponent that synchronous condensers would be used instead of a BESS (as outlined in section 2.3.5).

Figure 7-2 shows the composition of estimated net benefits for each option under the Step Change scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C, Option 7D and Option 7E in order to protect the confidentiality of these options. The level of wholesale market benefits for Option 5 and Option 6 (the Transgrid-owned BESS options) has also been redacted from this figure (and all figures of this type in the PACR) to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

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



The wholesale market modelling for the options involving BESS finds that the primary source of benefit is from avoided and deferred capex for new generation/storage (making up between 61 and 97 per cent of the wholesale market benefits for these options). However, the wholesale market benefits are relatively minor in the overall assessment for this scenario and only contribute between 0.4 and 12.3 per cent of the total estimated gross market benefits for the BESS options.

7.2. Progressive Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Progressive Change' scenario from the 2021 IASR. It also assumes the low demand forecasts (outlined in section 2.3.1) and the in-service renewable generators from Appendix B.

Under these assumptions, Option 7C is the top-ranked option and has net benefits that are approximately $14 million greater than Option 1C (the highest ranked network option), $20 million greater than Option 7E (the second highest ranked non-network option) and approximately $110 million greater than Option 7B (the lowest ranked non-network option).

This represents a change from the initial PACR, where Option 1C was the highest ranked option overall in the 'low economic benefits' scenario, followed by Option 3 and Option 4, and then Option 7C.

All options are found to have net costs under this scenario, 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 Step Change scenario. We note that the Progressive Change scenario reflects relatively conservative assumptions in the low demand forecast and we do not consider this result to change the key findings of this PACR (for the reasons outlined in section 7.4 below).

Further, if we did not apply the approach to removing unserved energy in the later years of the assessment period (outlined in section 6.1), then the results would show net benefits for Option 7C ($39 million), Option 1C ($25 million), Option 3 ($22 million), Option 4 ($22 million) and Option 7E ($19 million). The net costs would fall substantially for all other options (including net costs of $9 million, $9 million and $71 million respectively for Option 7D, Option 7A and Option 7B). In the ‘low economic benefits’ scenario from the initial PACR it was found that all options would still deliver net costs when all unserved energy were included in the analysis. The revised assumptions for the Progressive Change scenario in this PACR have led to an increase in the net benefits (or reduction in the net costs) of each option.

Figure 7-3 shows the overall estimated net benefit for each option under the Progressive Change scenario (with unserved energy in the later years of the assessment period removed, consistent with the other scenarios in this PACR).

Figure 7-3: Summary of the estimated net benefits under the Progressive Change scenario

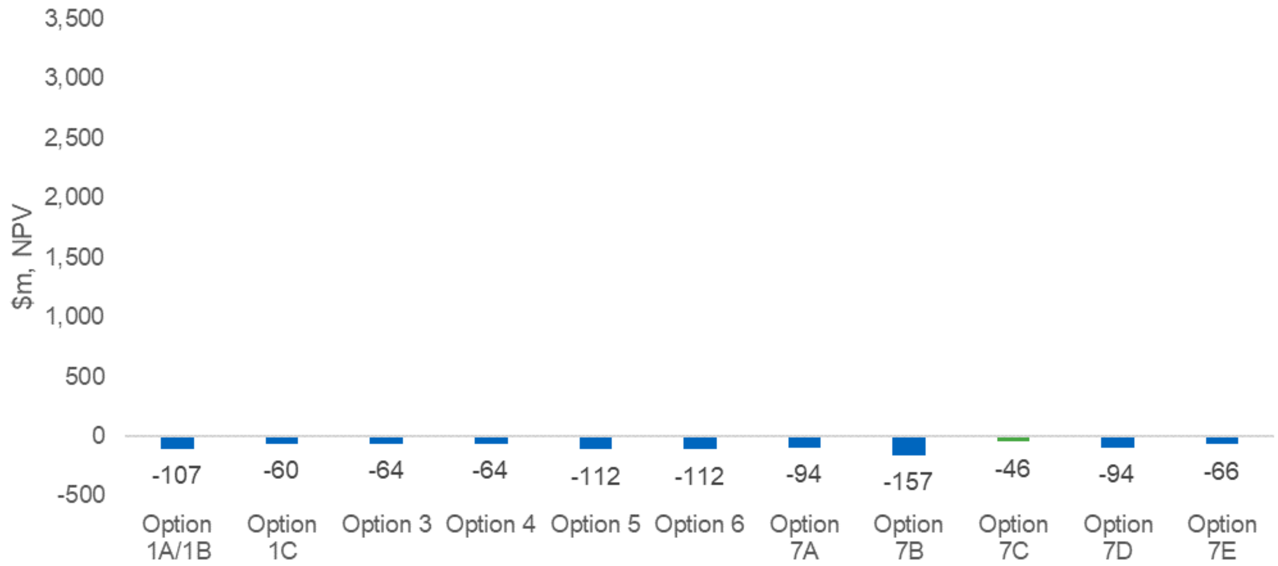
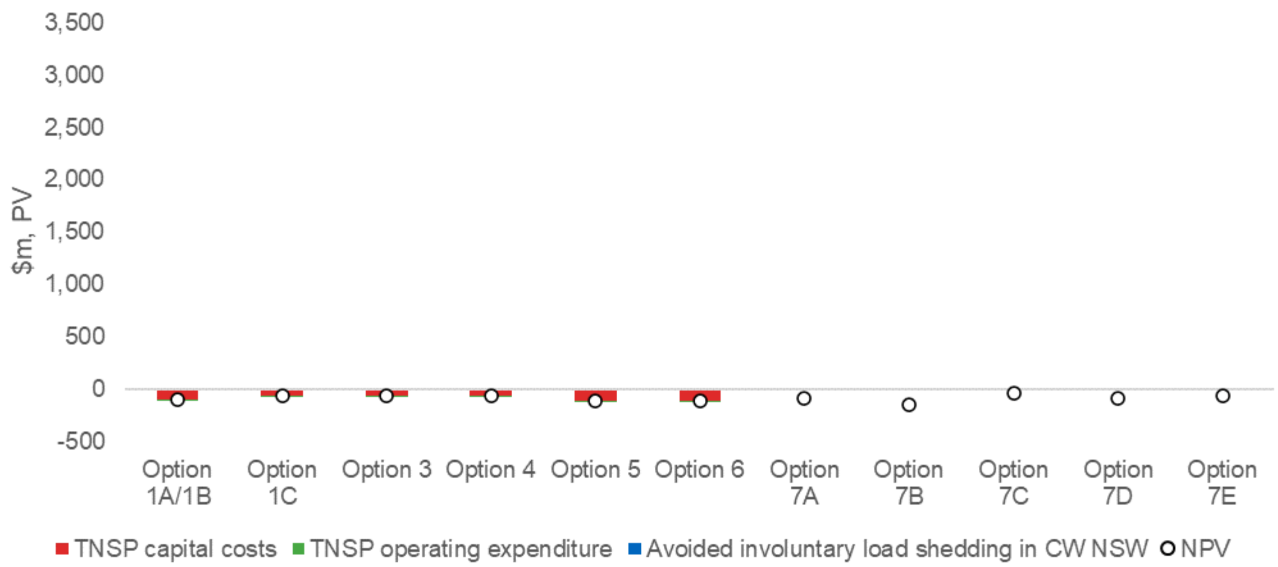


Figure 7-4 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C, Option 7D and Option 7E in order to protect the confidentiality of these options.

Figure 7-4: Breakdown of estimated net benefits under the Progressive Change scenario



As under the Step Change scenario, the wholesale market benefits are comprised almost exclusively of avoided and deferred capex for new generation/storage (making up approximately 96 per cent of the wholesale market benefits for this scenario on average across the options involving BESS). However, in contrast to the Step Change scenario, the wholesale market benefits make up between 36 and 95 per cent of the total estimated gross benefit for the BESS options under the Progressive Change scenario, as the avoided unserved energy benefits are substantially lower.

The Progressive Change scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the Progressive Change scenario used in the 2022 ISP. The wholesale market modelling finds that the Progressive Change scenario has marginally greater expected wholesale market benefits for options 7A-7C compared to the other two scenarios. This is due to the specific additional solar PV components in Option 7A and Option 7B (which cannot be commented on publicly) and the ability of Option 7C to arbitrage over Summer and Winter (which allows for more significant new open cycle gas turbine (OCGT) capacity to be avoided with the BESS for the Progressive Change scenario, compared to the other two scenarios).[60]

7.3. Hydrogen Superpower scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Hydrogen Superpower' scenario from the 2021 IASR. It also assumes the high demand forecasts (outlined in section 2.3.1) and the in-service and 'advanced' renewable generators from Appendix B.

Under these assumptions, as with the Step Change scenario, two of the options involving non-network solutions in the short-term (i.e., Option 7D and Option 7E) are preferred over the solely network options and other non-network options. They are strongly preferred over the network options 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 7D is the top-ranked option overall, with estimated net benefits that are approximately $149 million (2 per cent) greater than Option 7E and $6,519 million (369 per cent) greater than the preferred network option (Option 3).

The other three non-network options, Options 7A-7C, are also found to have net market benefits that are significantly greater than Option 3 (by between $448 million and $5,400 million).

Figure 7-5 shows the overall estimated net benefit for each option under the Hydrogen Superpower scenario.

[60] The relatively high level of new OCGT investment expected under the base case for the Progressive Change scenario, which is able to be avoided by the BESS options that can arbitrage in summer and winter, is due to the interaction between the retirement of Eraring in 2025-26, the timing of Humelink in 2035-36 (compared to 2027-28 and 2028-29 for the other two scenarios) as well as the relatively relaxed carbon constraint.

Figure 7-5: Summary of the estimated net benefits under the Hydrogen Superpower scenario

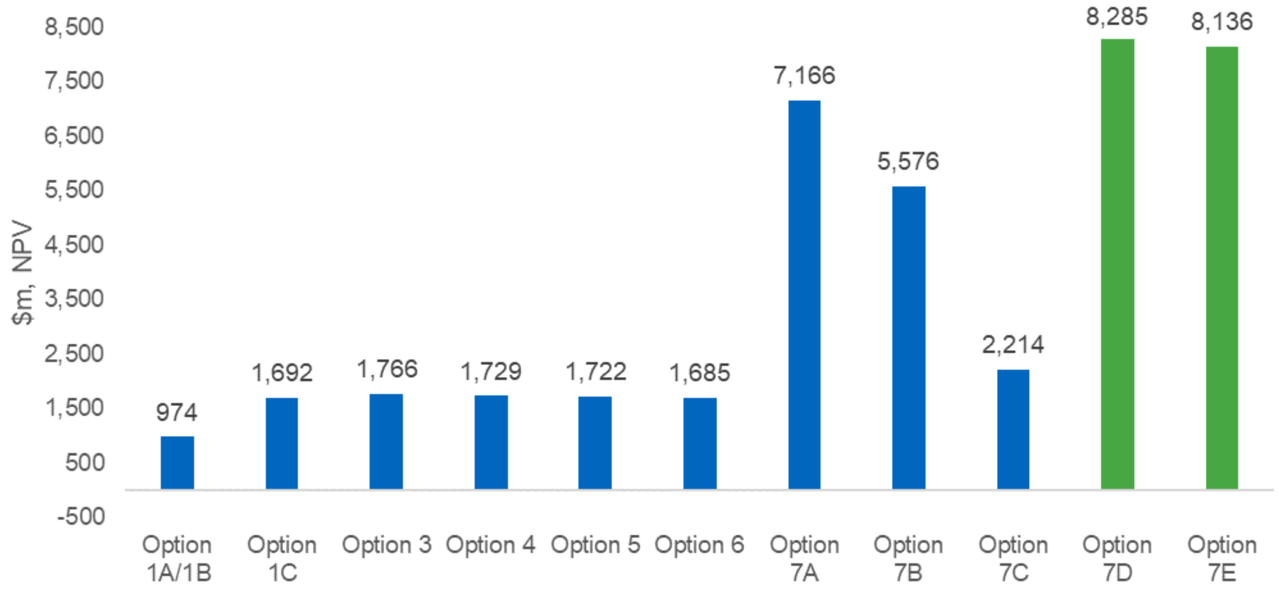
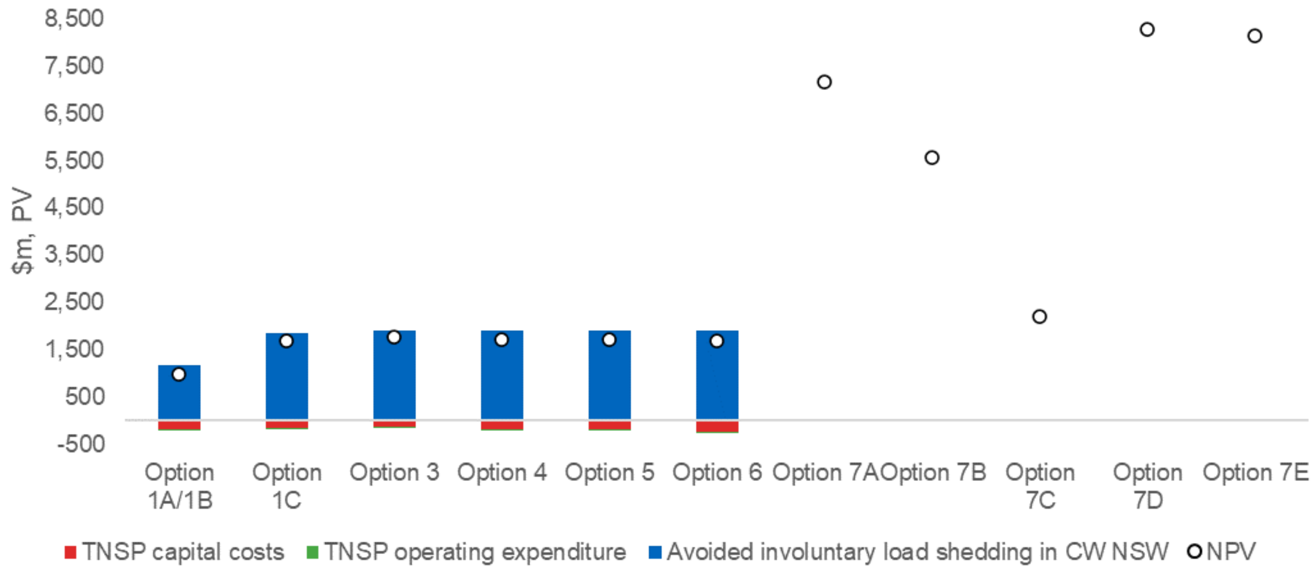


Figure 7-6 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C, Option 7D and Option 7E in order to protect the confidentiality of these options.

Figure 7-6: Breakdown of estimated net benefits under the Hydrogen Superpower scenario



The wholesale market modelling for the options involving BESS finds that the primary source of benefit is from avoided and deferred capex for new generation/storage (making up approximately 97 per cent of the wholesale market benefits on average across the options involving BESS). However, the wholesale market benefits are relatively minor in the overall assessment for this scenario and only contribute between 0.1 and 3.8 per cent of the total estimated gross market benefits for the BESS options.

7.4. Weighted net benefits

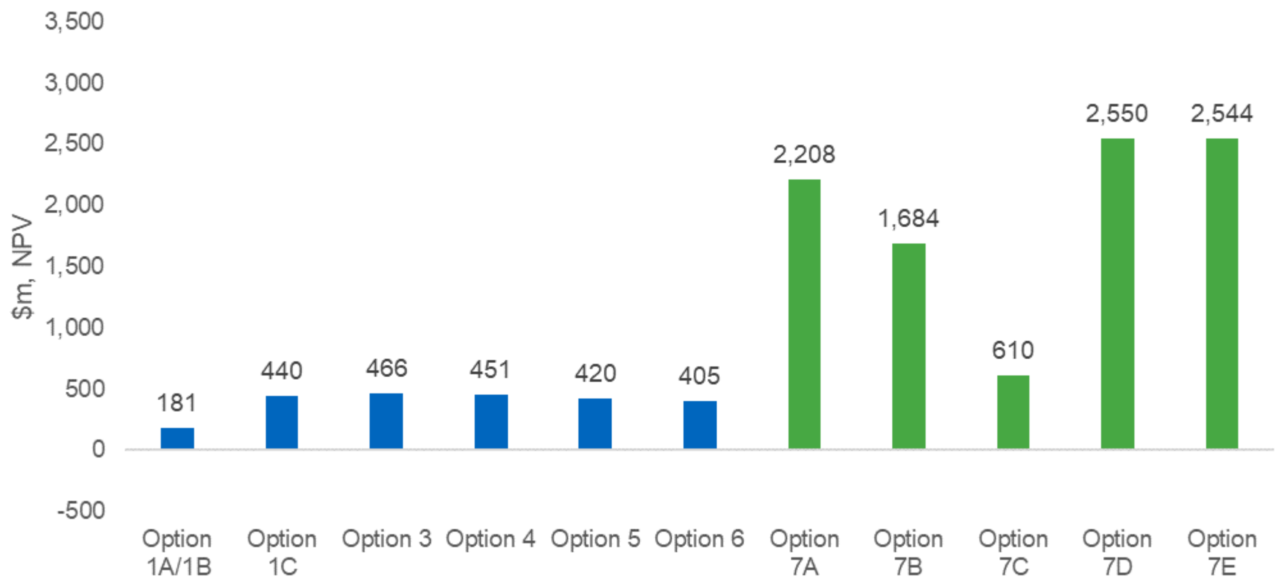
Figure 7-7 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above).

Under the weighted outcome, two of the options involving non-network solutions in the short-term (i.e., Option 7D and Option 7E) are preferred over the solely network options and other non-network options. They are strongly preferred over the network options due to these options being able to be commissioned approximately one to two years before the network options, which allows them to avoid substantial additional unserved energy.

Option 7D is the top-ranked option overall, with estimated net benefits that are approximately $6 million (0.3 per cent) greater than Option 7E and $2,084 million (447 per cent) greater than the preferred network option (Option 3).

The other three non-network options, Options 7A-7C, are also found to have net market benefits that are significantly greater than Option 3 (by between $144 million and $1,741 million).

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



While the Progressive Change scenario yields net costs for all options (or for a subset of the options if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR) and different top-ranked options, we do not consider this material to the overall conclusion of the RIT-T. The Progressive Change scenario would need to be given an unreasonably high weighting in order to change the conclusion of this PACR. Specifically, we find that the Progressive Change scenario would need to be given a weighting of approximately 95 per cent in order for a non-network option to be ranked below any of the network options.[61]

[61] We note that this weighting does not change if we value all avoided unserved energy in the assessment, i.e., if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR.

Overall, 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 7.5.7 below.

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 sensitivity tests has been expanded from the initial PACR in-line with the AER dispute determination.

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

- a higher demand forecast for a key mining load;
- the VCR;
- different commercial discount rates;
- capital costs for both network and non-network options;
- the impact of different spot load forecasts;
- scenario weightings; and
- the assumed timing of both the network and non-network components

Each of the sensitivity tests undertaken in this PACR are discussed in the sections below. Each sensitivity test has been undertaken for all scenarios, consistent with the AER dispute determination,[62] but the discussion of each focuses on the weighted outcome since it is what is relevant for the RIT-T.

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. A higher demand forecast for a key mining load

A confidential mining load in the Orange area has advised that it may experience higher demand forecasts than what has been included in the assessment (as described in section 2.3.1). While we consider that this additional load growth is not sufficiently advanced to be included in the assessment for this RIT-T (based on information provided by the proponent), we have performed an assessment assuming that this higher demand forecast eventuates.

If this additional load growth were to eventuate, it will exaggerate the identified voltage constraints (see section 2.3.2) and also result in thermal constraints under (N-1) contingency conditions. While this may impact on the timing and preferred component for Stage 2 of the project, it does not impact on the outcome of Stage 1 considered under this RIT-T. We have included a contingent project for the Stage 2 works in our 2023-28 Revenue Proposal for which we intend to undertake a further RIT-T and will take into account updated demand forecasts at that later date.

7.5.2. VCR

Estimates of the VCR are crucial to determining the value of avoided unserved energy but are subject to uncertainty and so, in addition to using the central VCR estimates, we have also assumed VCR estimates

62 AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, p. 6.

that are 30 per cent lower and 30 per cent higher, consistent with the AER's specified +/- 30 per cent confidence interval.[63]

The ranking of the options on a weighted basis does not change under either sensitivity, as demonstrated by the two figures below.

Figure 7-8 presents the results under the 30 per cent lower VCR of $38.18/kWh.

63 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.

Figure 7-8: Weighted net benefits under a 30 per cent lower VCR

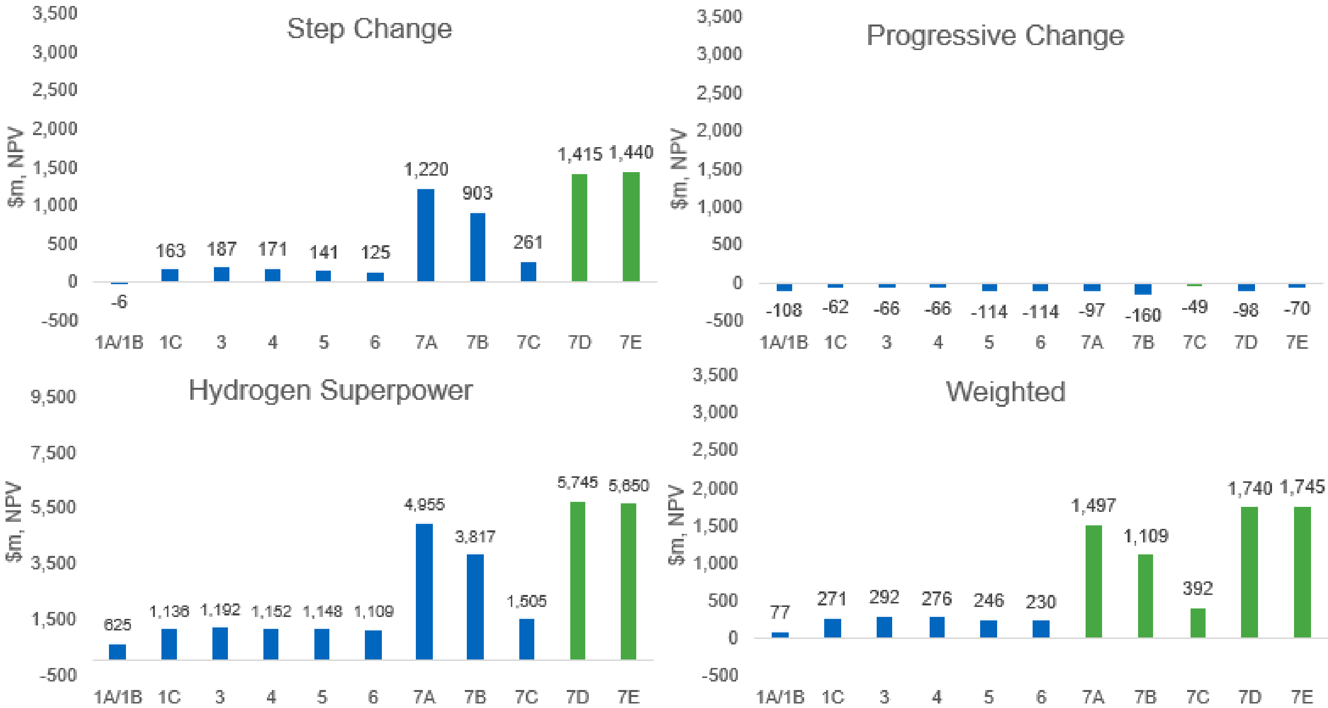
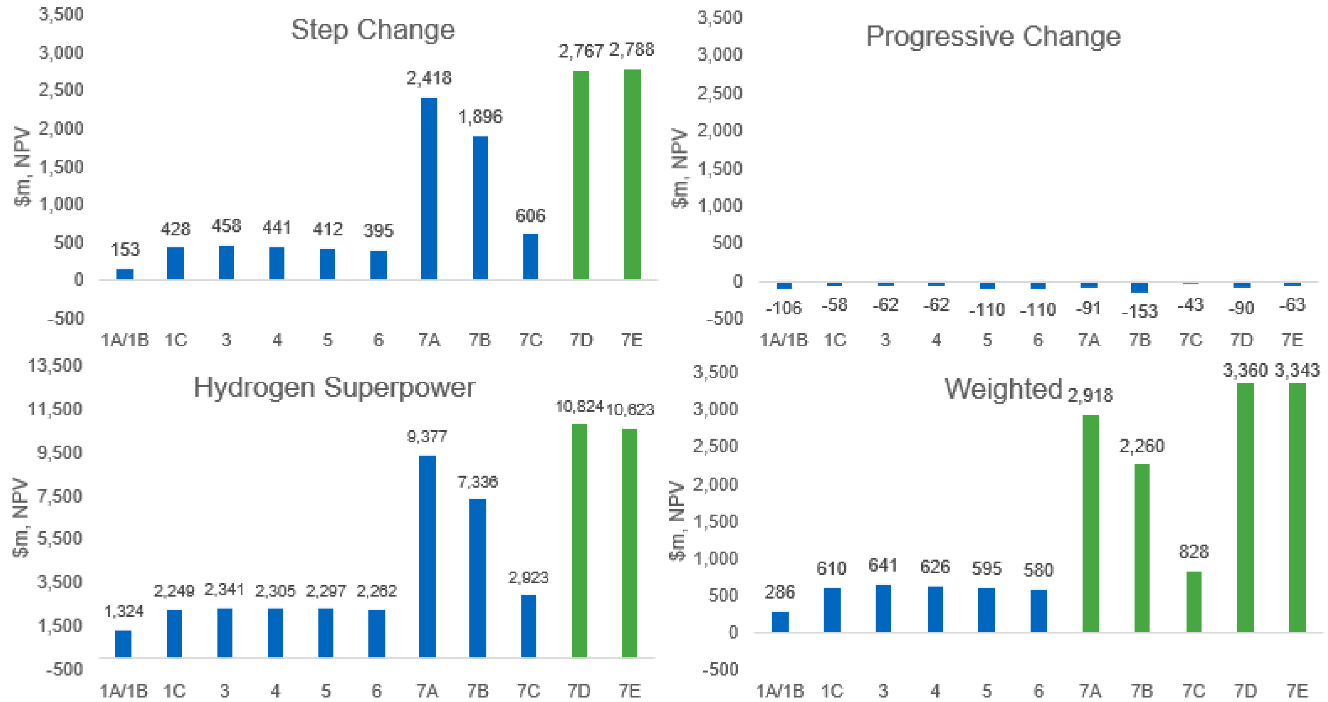


Figure 7-9 presents the results under the 30 per cent higher VCR of $70.91/kWh.

Figure 7-9: Weighted net benefits under a 30 per cent higher VCR



7.5.3. Commercial discount rate

The discount rate directly affects the trade-off between costs now and benefits in the future.

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 amended PACR, consistent with the assumptions adopted in the 2021 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 2.30 per cent,[64] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound used for the 2022 ISP[65]).

Neither sensitivity changes the ranking of the options on a weighted basis, as demonstrated by the two figures below.

Figure 7-10 presents the results under an upper bound discount rate of 7.50 per cent.

Figure 7-10: Weighted net benefits under 7.5 per cent discount rate

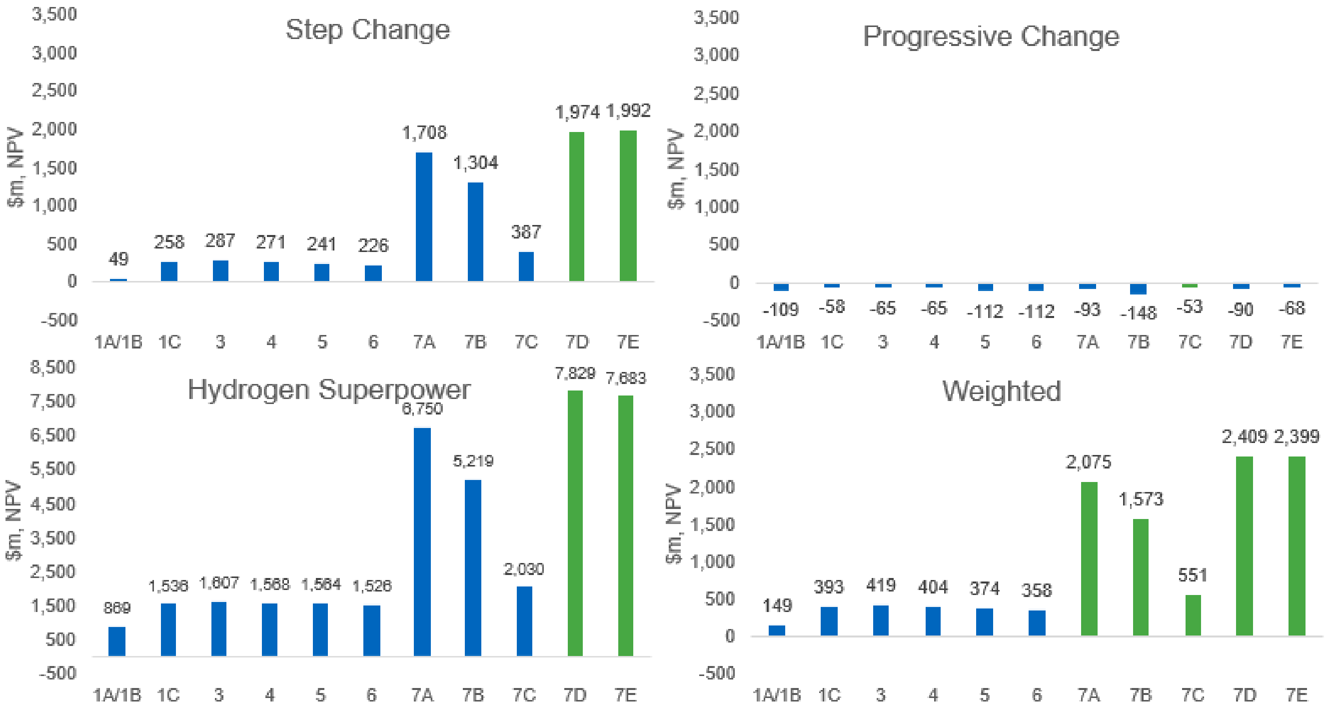


Figure 7-11 presents the results under a lower bound discount rate of 2.3 per cent, based on the latest regulated pre-tax WACC for an electricity transmission business in the NEM.[66]

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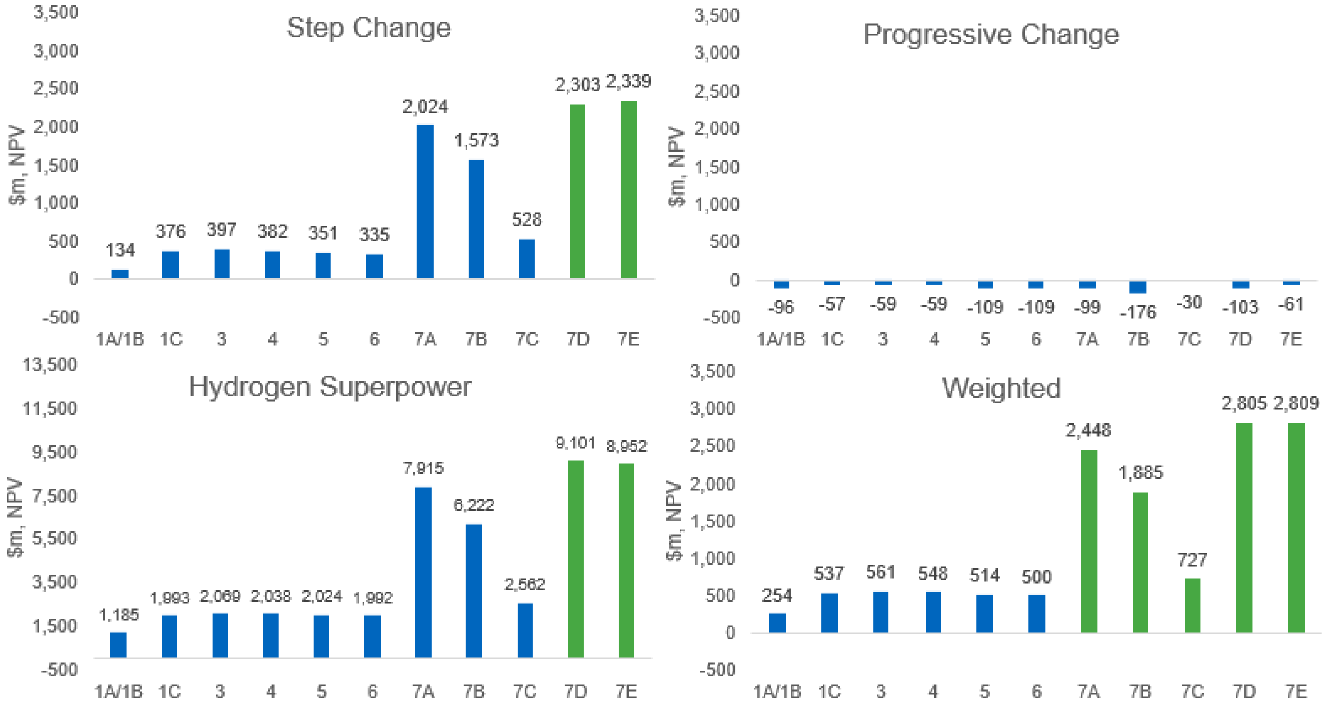
64 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23..

65 AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.

66 AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23. We note that applying a discount rate of 1.96 per cent, as per the AER's previous final decision for AusNet Services (which was the latest final decision at the time of the initial PACR), also would not change the rankings of the options.

Figure 7-11: Weighted net benefits under 2.3 per cent discount rate



7.5.4. Capital costs for both network and non-network options

We have investigated the sensitivity of the option rankings to differences in the capital cost forecasts.

Changing the capital costs for both network and non-network options (25 per cent lower and higher) does not change the rankings of the options on a weighted basis. This is because the primary driver of differences between the options is the difference in avoided unserved energy benefits.

Figure 7-12 shows the results with 25 per cent higher network capital costs.

Figure 7-12: Weighted net benefits under 25 per cent higher network capital costs

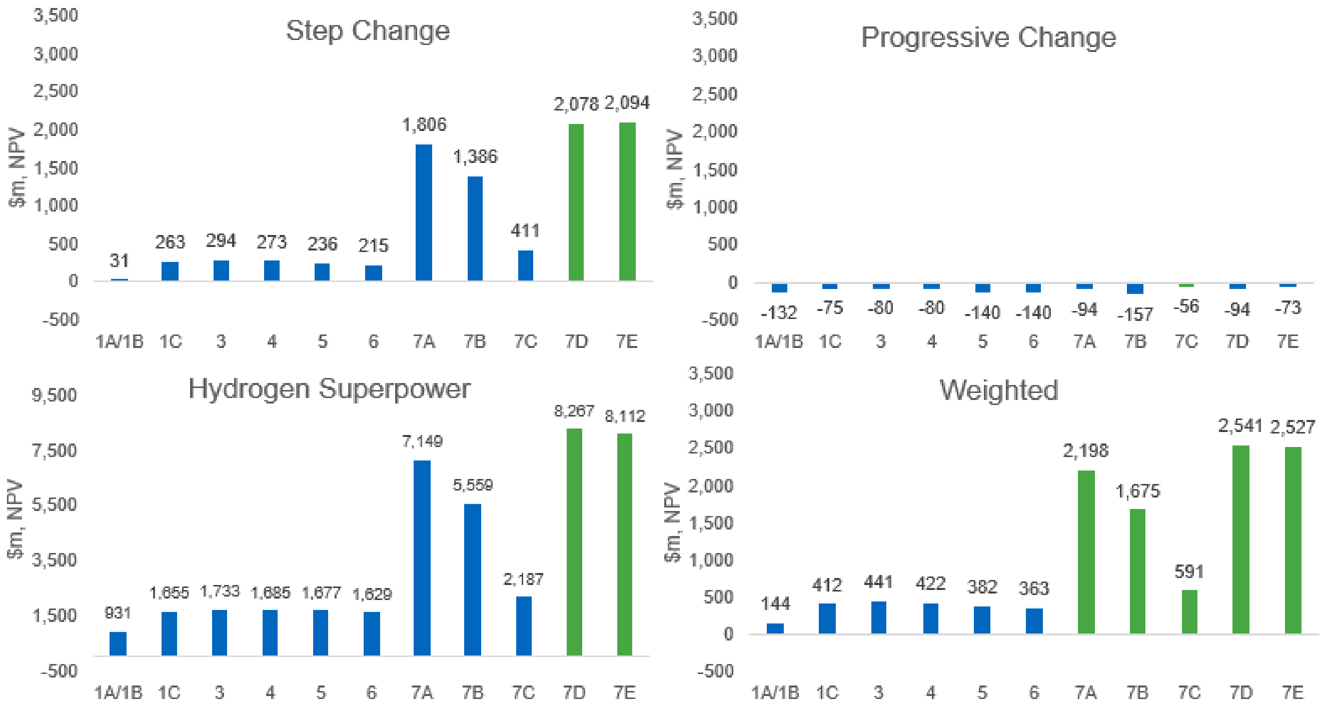


Figure 7-13 shows the results with 25 per cent lower network capital costs.

Figure 7-13: Weighted net benefits under 25 per cent lower network capital costs

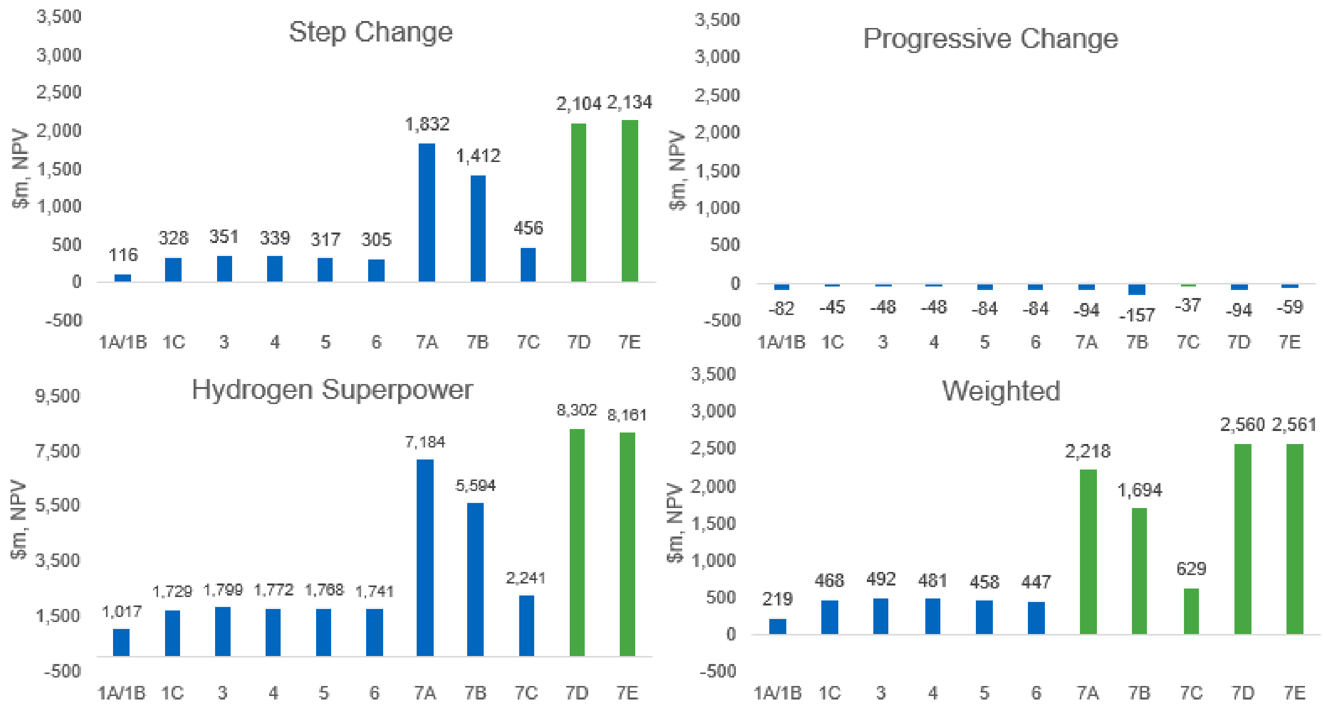


Figure 7-14 shows the results with 25 per cent higher non-network capital costs.

Figure 7-14: Weighted net benefits under 25 per cent higher non-network capital costs

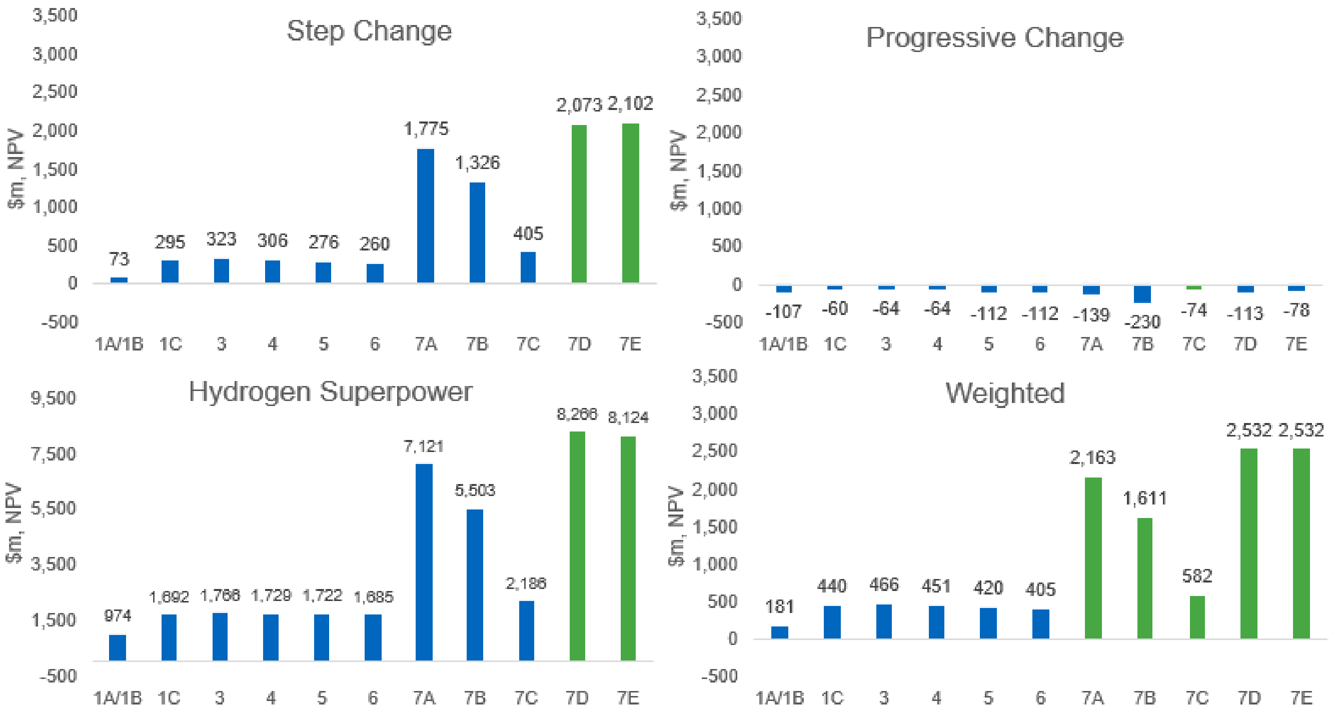
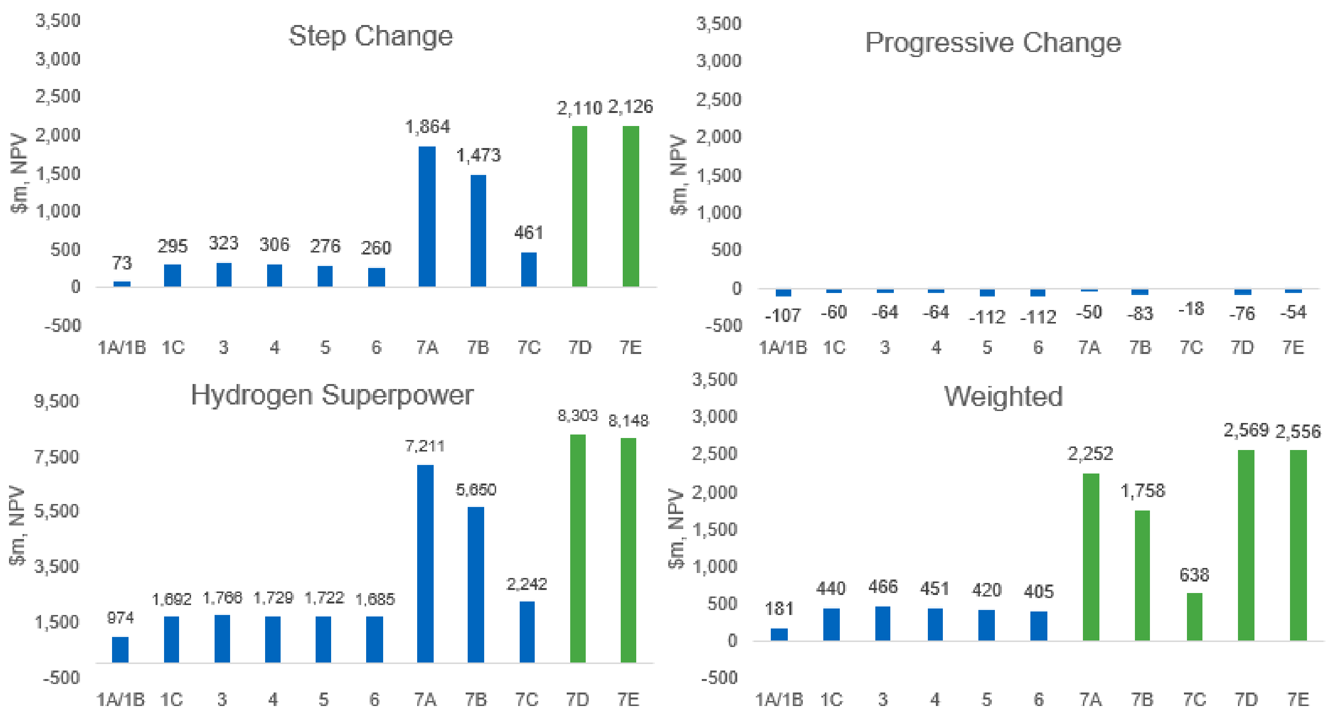


Figure 7-15 shows the results with 25 per cent lower non-network capital costs.

Figure 7-15: Weighted net benefits under 25 per cent lower non-network capital costs

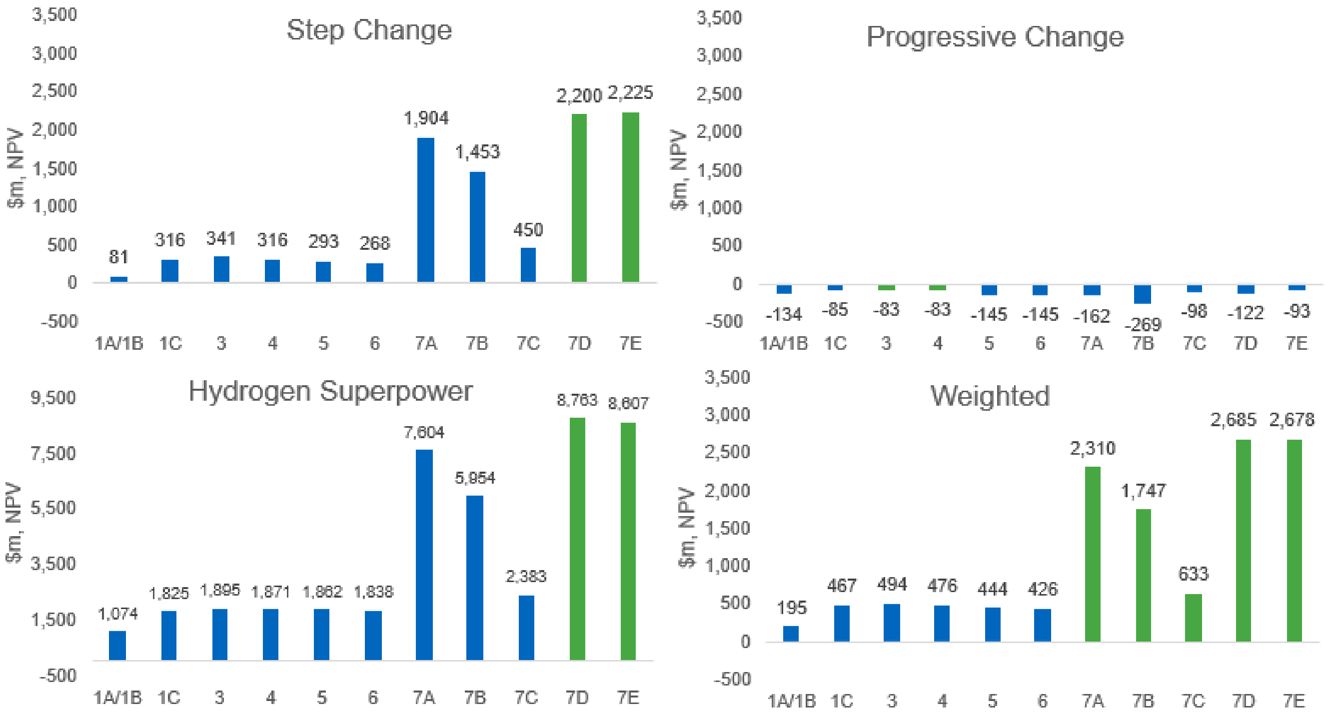


We have also extended this sensitivity and applied Transgrid's updated 2022 unit rate costs, updated from the 2021 unit rates as part of our annual cost estimating database update to capture the latest market pricing and observed cost movements. This aligns with our Revised Revenue Proposal for network capital costs (as well as also increasing non-network costs by the same proportion as the updated network costs). These updated unit rates:[67]

- reflect the high and unexpected inflation over the 12 months to June 2022, driven by a range of factors beyond our control; and
- are more recent and therefore provide the best available information for the purpose of forecasting future capex.

Figure 7-16 presents the results for each scenario under the unit rate update with non-network costs increasing by the same proportion as the updated network costs. There is no change to the ranking of the options relative to the core results on a weighted basis.

Figure 7-16: Weighted net benefits under updated unit rates with proportional NNO cost increase



We have also undertaken boundary testing on the network capital costs. In relation to the preferred option (Options 7A-7E):

- An increase in the costs of the Wellington to Parkes 132 kV line component affects Options 7A – 7E and Option 3 equally. Therefore, the rankings of Options 7A – 7E and Option 3 would not change following an increase in the costs of the Wellington to Parkes line.
- There is no realistic increase in the costs of the network components of Options 7A – 7E that would make any of the network only options preferred over Options 7A – 7E.[68]

We consider that changes in costs of this magnitude are unlikely, given the +/-25 per cent estimation accuracy adopted for the cost estimates.

[67] Transgrid, 2023-28 Revised Revenue Proposal, December 2022, pp. 67-68.
[68] If the capital costs of the network components of Option 7C w ere to increase by more than 194 per cent, then Option 1C would be ranked above Option 7C. It would require a much greater increase in the network costs of Option 7A, 7B, 7D and 7E for any network only option to be preferred over these options.

In relation to the preferred network only option (Option 3):

- An increase of more than 34 per cent (or $41.6 million) in the cost of the Wellington to Parkes 132 kV line component would be required to change the ranking of the credible network only options (ie, to make Option 4 preferred over Option 3).
- An increase of more than 23 per cent (or $46.8 million) in the total cost of Option 3 would be required to change the ranking of the credible network only options (to make Option 1C preferred over Option 3).
- In both cases, Option 7A-7E remains preferred to a network only option because of the benefit of avoiding USE sooner for options that have a non-network component

We consider that if these changes in the costs of Option 3 were to occur, they are likely to be accompanied by changes in the costs of similar components of Option 1C and Option 4 given the commonality in underlying resource cost drivers of these components.[69] Therefore, we consider changes in costs that would lead to a change in the rankings of the purely network options to be unlikely.

7.5.5. The impact of different spot load forecasts

The primary source of market benefit for this RIT-T is avoided unserved energy in the Orange and Parkes region and so we have investigated sensitivities involving different demand forecasts outside of the three demand forecasts used in the core assessment.

These sensitivities highlight the extent to which investments are dependent on key spot load.

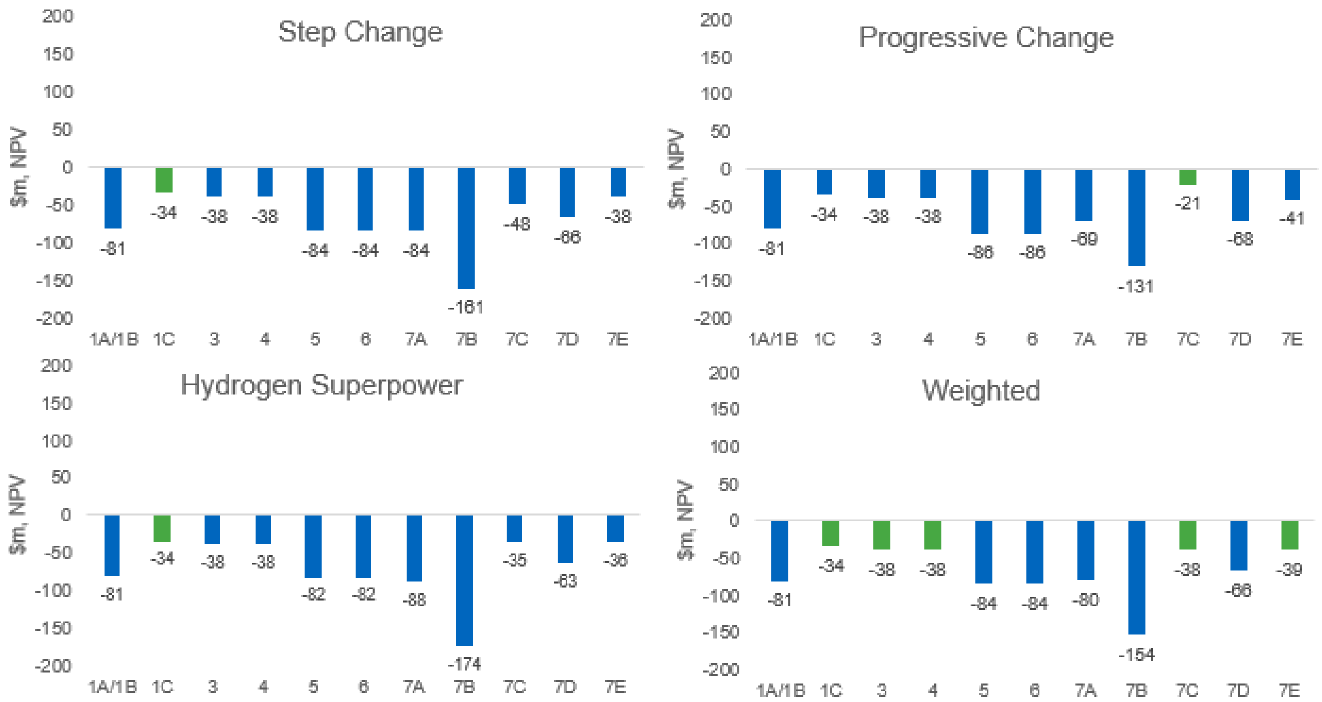
As explained in section 6.1, unserved energy after 2027/28 was removed from the core analysis for clarity of presentation. When anticipated spot loads are excluded from the analysis, it is no longer necessary to zero out the unserved energy to make the results more readable. However, we have also presented the results continuing to apply the approach to zeroing out unserved energy explained in section 6.1 for consistency.

Figure 7-17 presents the NPV results of removing all anticipated spot load and includes all avoided unserved energy benefits in the analysis.

We note that stage 2 of the non-network option (ie, Options 7A-7E) and stage 2 of Option 3 would not be commissioned under this sensitivity due to the exclusion of anticipated load in all scenarios – in both cases stage 2 is the 132kV line from Wellington to Parkes. We have applied the series of investments and commissioning dates applicable for this level of load, which is identical to that used in the Progressive Change scenario from the core results.

[69] Examples of similar components across Option 3, Option 4 and Option 1C include transmission lines in a different location, or synchronous condensers of a different size.

Figure 7-17: Weighted NPV results with all anticipated load removed from the analysis (avoided unserved energy after 2028 included)

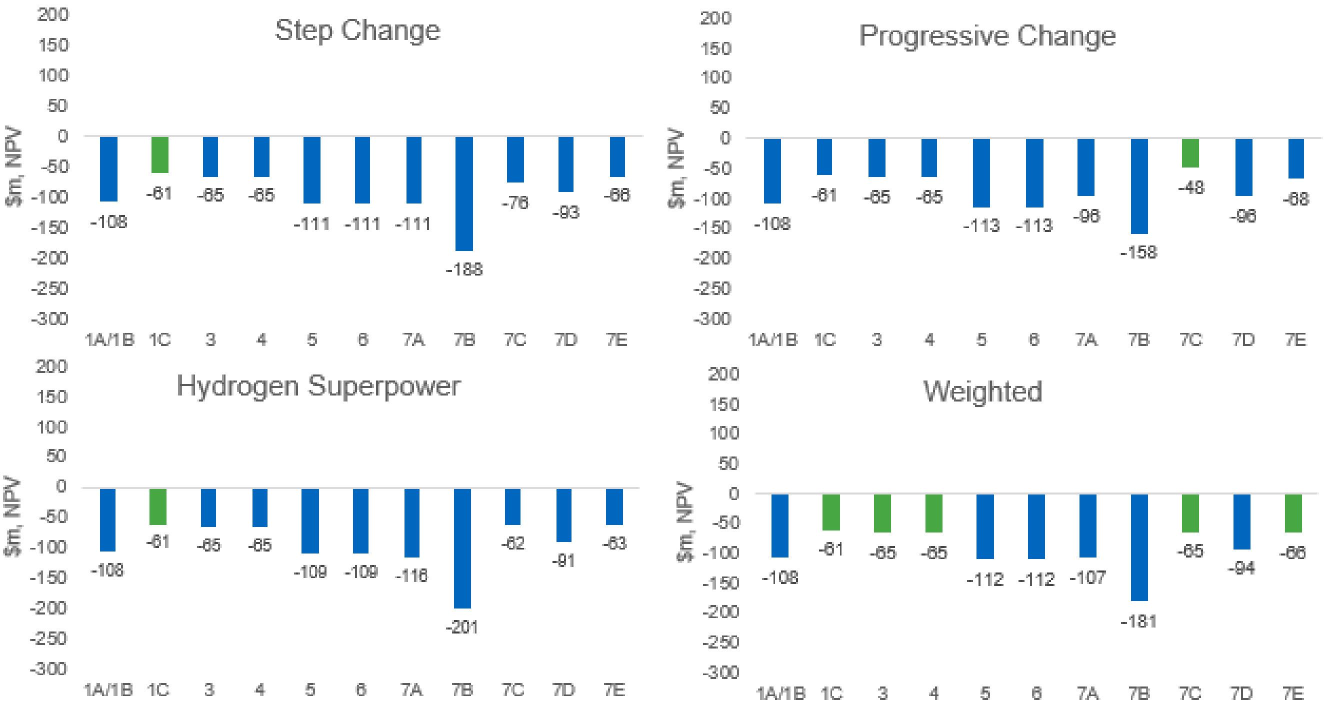


The removal of all anticipated spot load has a significant impact on the results, because the core results are largely driven by avoided unserved energy benefits. While Option 1C becomes the top ranked option, there are five options (Option 1C, Option 3, Option 4, Option 7C and Option 7E) ranked within $5 million of each other.

We consider that a scenario where none of the currently anticipated spot load goes ahead is unlikely, as there are a substantial number of potential spot loads in the area.

Figure 7-18 is included for completeness and presents the NPV results of removing all anticipated spot load and excludes all avoided unserved energy benefits after 2027/28 from the analysis (in line with section 6.1).

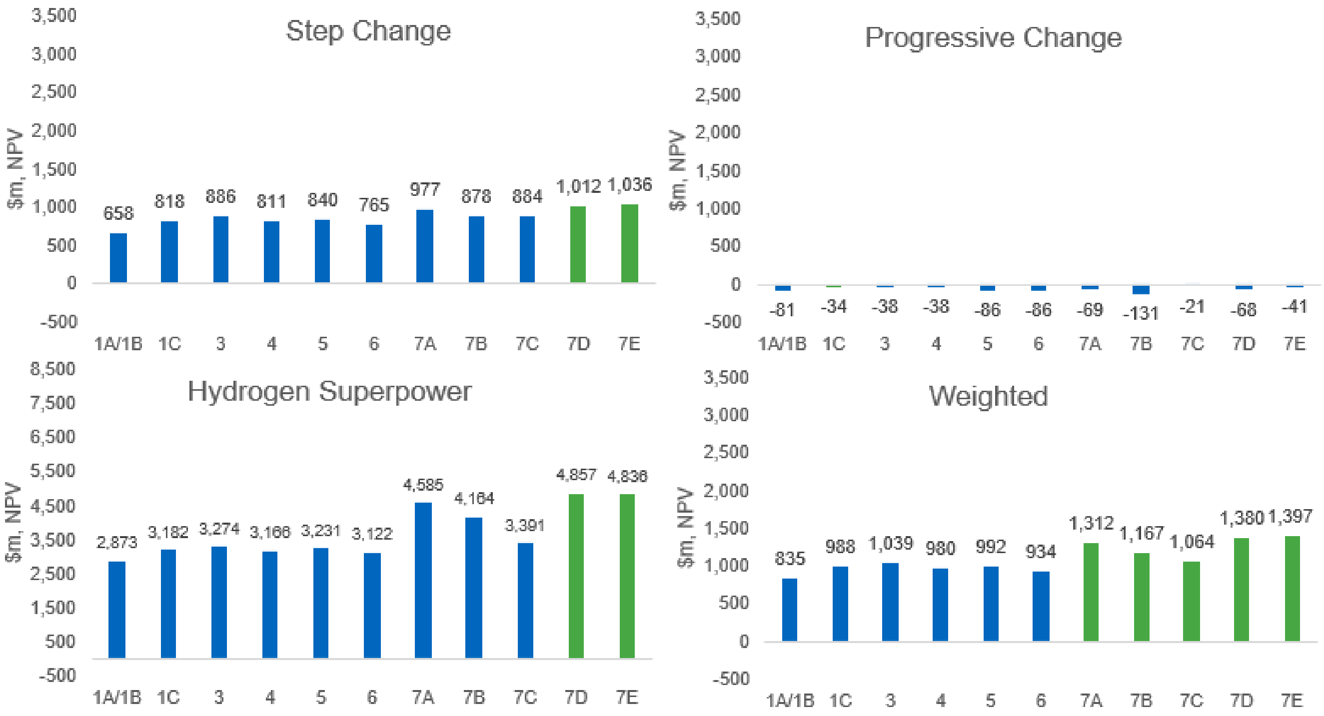
Figure 7-18: Weighted NPV results with all anticipated load removed from the analysis (avoided unserved energy after 2028 excluded)



We have also investigated the effect of removing only the Parkes Special Activation Precinct (SAP) from the analysis (and keeping other anticipated spot loads).

Figure 7-19 presents the NPV results of removing the Parkes SAP and includes all avoided unserved energy benefits in the analysis. We have applied the series of investments and commissioning dates applicable for this level of load. This means that the Wellington to Parkes line in Stage 2 of Option 3 and each of the non-network option would not be required.

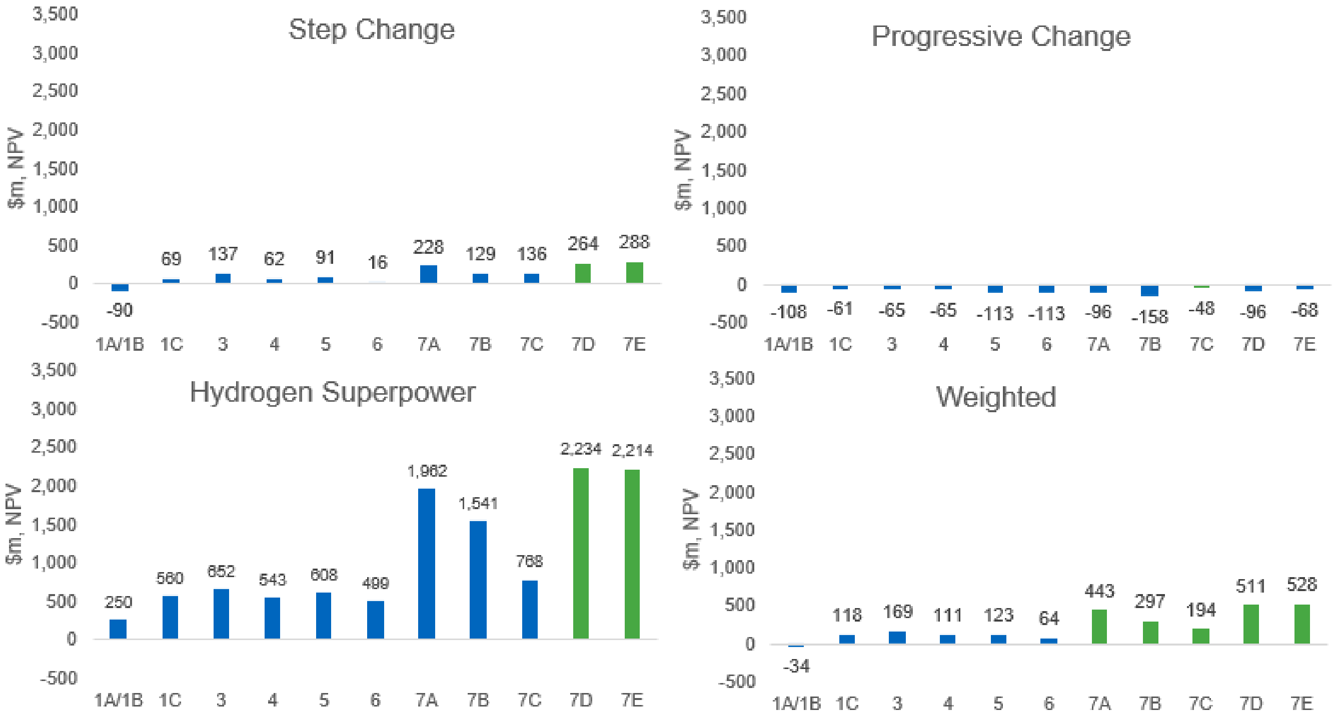
Figure 7-19: Weighted NPV results with Parkes SAP removed from the analysis (avoided unserved energy after 2028 included)



The ranking of the options does not change under this sensitivity, except that Option 3 would be ranked effectively equally to Option 7C. However, all other non-network options remain clearly preferred to the network options.

Figure 7-20 presents the NPV results of removing the Parkes SAP and excludes all avoided unserved energy benefits after 2027/28 from the analysis (in line with section 6.1).

Figure 7-20: Weighted NPV results with Parkes SAP removed from the analysis (avoided unserved energy after 2028 excluded)



7.5.6. Scenario weightings

The findings of the amended PACR assessment mean that applying equal weightings (on the basis that there is no information as to whether one demand outcome is more likely than another), or the PADR '25:50:25' weights (as it could be argued that the central demand forecast has been constructed to be the more likely), do not change the conclusion of this RIT-T, i.e., that Option 7D and Option 7E are ranked effectively equal first overall, with all non-network options being preferred to any network option and Option 3 being the highest ranked purely network option. This is illustrated in the two figures below.

Figure 7-21 presents the results of applying equal weightings to each of the Step Change, Progressive Change and Hydrogen Superpower scenarios.

Figure 7-21: Weighted net benefits applying equal weighting to each scenario

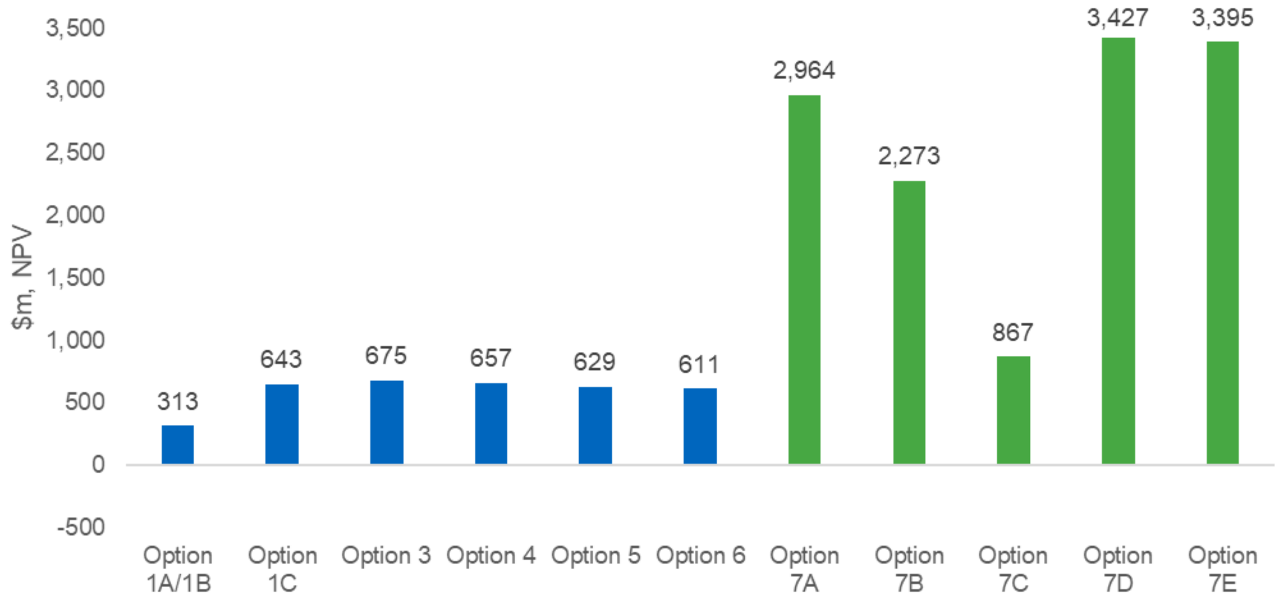
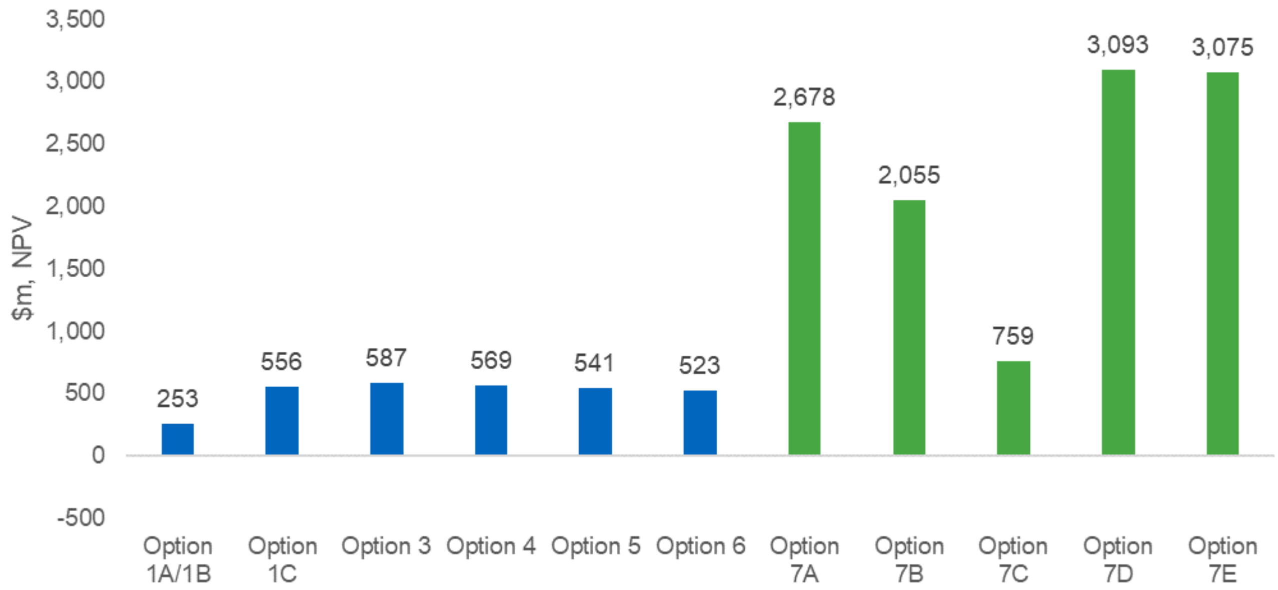


Figure 7-22 presents the results of using '25:50:25' weighting, in line with the PADR.

Figure 7-22: Weighted net benefits applying the PADR '25:50:25' weighting



The Progressive Change scenario would need to be given an unreasonably high weighting in order to change the conclusion of this amended PACR. Specifically, we find that the Progressive Change scenario would need to be given a weighting of approximately 95 per cent in order for a non-network option to be ranked below any of the network options.[70]

[70] We note that this weighting does not change if we value all avoided unserved energy in the assessment, i.e., if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR.

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

As outlined in section 7.4, a 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 table below investigates the effects of assuming earlier commissioning dates for the top-ranked solely network option (Option 3) as well as assuming later commissioning dates for the options involving non-network components (Options 7A-7E). Specifically, Table 7.1 shows the net market benefits under various alternate timing assumptions, with red text denoting the top-ranked option (and any other option within 5 per cent of the top-ranked option).

Table 7.1: Alternate timing sensitivities ($m, NPV), weighted

	Option 3	Option 7A	Option 7B	Option 7C	Option 7D	Option 7E
Core result	466	2,208	1,684	610	2,550	2,544
Option 3 one year forward	1,618	2,208	1,684	610	2,550	2,544
NNO one year delay	466	1,121	408	276	1,997	1,605
Option 3 forward and NNO delay	1,618	1,121	408	276	1,997	1,605

Red text denotes the preferred option and any option within 5 per cent of the preferred option

While the table above shows that bringing forward Option 3 by one year results in it having greater net benefits than Option 7C and Option 7B, we do not consider this feasible and, at most, consider it could be expedited by six months.

The table above also highlights the sensitivity of the individual non-network options to their assumed commissioning date. Specifically, it shows that with a one year delay to the date assumed in the core analysis, Option 7B and Option 7C are no longer preferred over Option 3. This highlights the importance of these solution being able to be delivered as soon as possible (and, importantly, by the dates proposed by proponents).

8. Conclusion

The preferred option identified in this amended PACR remains unchanged from the initial PACR and involves the use of a non-network solution provided via new BESS at Parkes and Panorama and the installation either STATCOMs at Parkes and Panorama or a synchronous condenser (as a network investment) at Parkes in the near-term. It also involves a new 132 kV line between Wellington and Parkes in the future, with the date of this line depending on what happens with outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 7D and Option 7E in the PACR, and reflect the proposed BESS components followed by the network investment outlined above. These options are found to deliver approximately $2,550 million and $2,544 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $466 million for the top-ranked solely network option (Option 3).

The proposals of the other three non-network proponents (Option 7A, Option 7B and Option 7C, which variously involve BESS and other technologies) have been found to deliver lower net benefits than the two top-ranked options (when coupled with the later 132 kV Wellington-Parkes line), but also to be ranked significantly ahead of Option 3.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider all five proponents should be involved in these negotiations (i.e., including Option 7A, Option 7B and Option 7C, which have lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when non-network support can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process, compared to two, will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3 should be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet (i.e., Schedule 5.1.4 of the NER) are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the Bathurst, Orange and Parkes area and ultimately likely cost all NSW electricity customers more in the long-run.

We note that the NER regarding a 'material change in circumstances', and the ability to include 'reopening triggers'[71] in a PACR have recently been considered by the Australian Energy Market Commission.[72] The final rule requires RIT-T proponents of projects with an estimated cost of more than $100 million to develop reopening triggers that clearly indicate whether there has subsequently been a material change in circumstances following completion of the RIT-T.[73] While the new rule requirements do not apply to this RIT-T, consistent with the final rule made, we consider the events above to constitute two elements of an effective reopening trigger for this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that Option 3 should instead be progressed (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

As stated in our recently submitted Revised Revenue Proposal for the 2023-2028 period, we intend to rely solely on a non-network solution comprising of a BESS at Parkes and Panorama and the installation of static synchronous compensators (STATCOMs) at Parkes and Panorama (as a non-network solution). Given the need to still finalise a network support agreement, we have included the alternative network investment (i.e., a synchronous condenser) that could be coupled with a non-network BESS, as a contingent project for the upcoming regulatory period. We have also included a fully-network option as a contingent project in case the non-network solutions are found not to be technically feasible, or if we are unable to conclude network support agreements in time to meet our regulatory obligations, although we are working hard to avoid this outcome. More information on our 2023-28 Revised Revenue Proposal can be found here.

We consider that the preferred option, as defined above, satisfies the RIT-T.

71 We note that what was originally referred to as 'decision rules' at the time of the initial PACR has been relabelled as 'reopening triggers' by the AEMC to differentiate this approach from the decision rules AEMO uses for the ISP. See AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. 9.
72 AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.
73 AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. ii.

Appendix A Compliance checklist

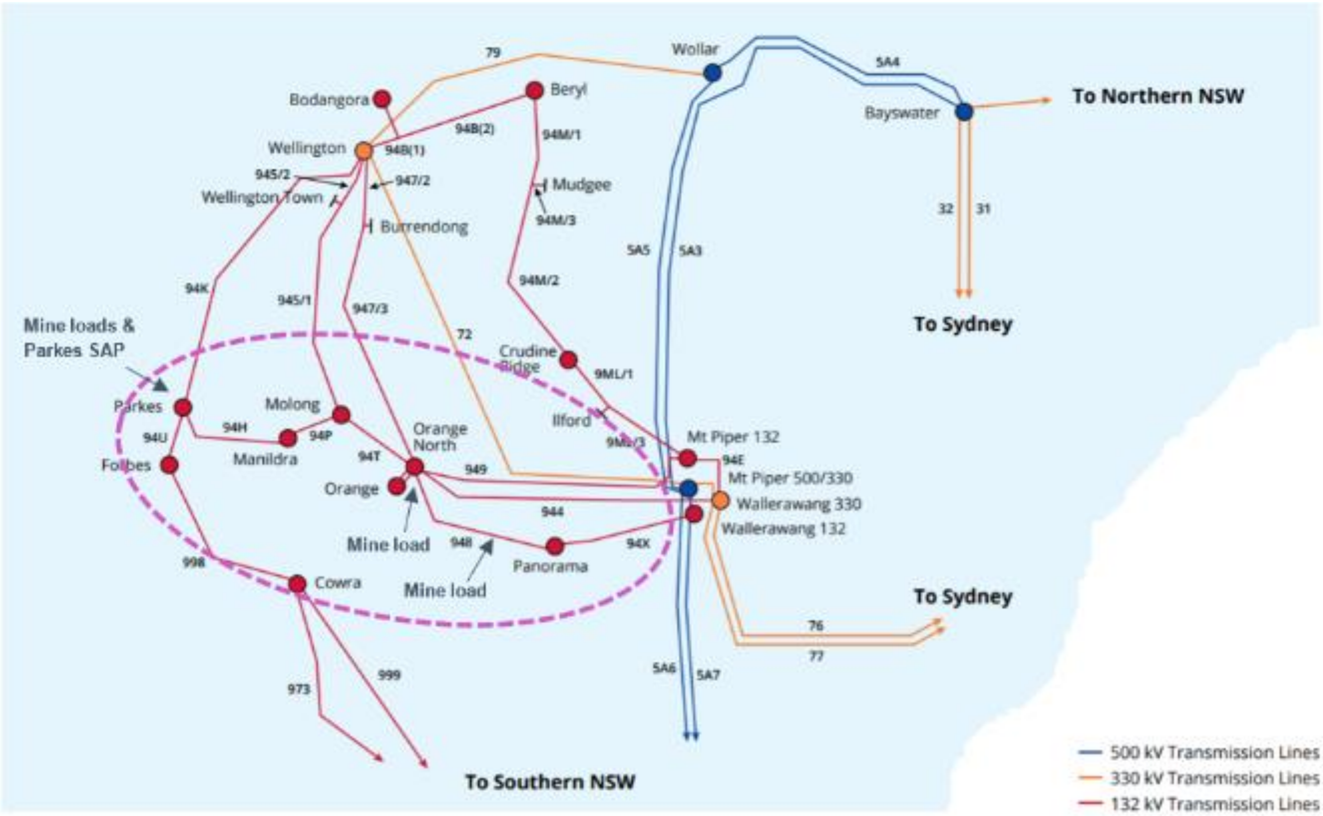
This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 194.

Rules clause	Summary of requirements	Relevant section(s) in the **PACR**
5.16.4(v)	The project assessment conclusions report must set out:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	3 Appendix E
5.16.4(k)	The project assessment draft report 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;	4 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & Appendix D
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.5
	(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;	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.	8

Appendix B Overview of existing electricity supply arrangements in central west NSW

The current central west NSW electricity transmission network is shown in Figure B-1 below. The area relevant for this RIT-T is around Orange and Parkes and is circled below. The indicative location of key forecast electricity loads (which have been publicly announced) are also shown with arrows.

Figure B-1: Central west NSW transmission network



Electricity demand in central west NSW is forecast to increase significantly over the next ten years, primarily due to:

- expected demand growth in some existing large industrial loads (the names, locations and loads have been redacted due to confidentiality reasons);
- planned connections of new industrial loads, i.e. McPhillamy's mine[74] and Sunrise mine;[75] and
- the NSW government's Parkes Special Activation Precinct (SAP).[76]

Essential Energy forecasts increased load from some of the existing large industrial loads in the area going forward. The specific details regarding the mines, locations and load forecasts has not been provided for confidentiality reasons.

In addition, going forward, there are two further mines expected to connect in the region. Namely:

74 https://www.regisresources.com.au/McPhillamys-Gold-Project/mcphillamys-gold-project.html
75 https://www.cleanteq.com/sunrise-project/
76 https://www.nsw.gov.au/snowy-hydro-legacy-fund/special-activation-precincts/parkes-special-activation-precinct

- the McPhillamy's gold mine, which is currently planned to connect within the next few years;[77] and
- CleanTeQ Sunrise Nickel-Cobalt-Scandium mine, which is also planned to connect within the next few years.[78]

These loads are located, or expected to be located, around Orange and Parkes in the central west region.

Specific load information for each of the expected mines has not been presented in this PACR due to this information being commercially sensitive. However additional information relating to the overall demand forecast is provided in Appendix C.

There are a number of in-service and planned renewable generator connections in the central west region, particularly around Parkes. Table B-1 summarises these systems. The only change from the initial PACR is that the Jemalong Solar Farm is now in-service, rather than 'committed'.

Table B-1: Current and planned renewable generation in the central west region

Generating System	Connection location	Capacity (MW)	Status
Parkes Solar Farm	Parkes 66 kV Busbar	50.5	In service
Manildra Solar Farm (EssE)	Manildra 11 kV Busbar	50	In service
Goonumbla Solar Farm	Parkes 66 kV Busbar	70	In service
Molong Solar Farm	Molong 66 kV Busbar	30	In service
Suntop Solar Farm	Line 94K (Wellington – Parkes tee Suntop Solar Farm)	150	In-service
Jemalong Solar Farm (EssE)	West Jemalong 66 kV Busbar	50	In-service
Flyers Creek Wind Farm (EssE)	Orange North 132 kV	138	Advanced*
Quorn Park Solar Farm (EssE)	Parkes 132 kV	80	Advanced*

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

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, commissioning, advanced and committed renewable generation in assessing the identified need for this RIT-T.

[77] https://www.regisresources.com.au/McPhillamys-Gold-Project/mcphillamys-gold-project.html
[78] https://www.cleanteq.com/sunrise-project/

Appendix C Additional detail as to the basis for including potential spot loads in the analysis

The table below summarises all key loads in the area and the rationale for including them in the spot load forecasts used in this amended PACR (and the initial PACR).

While some have had to be redacted due to confidentiality reasons, the detail regarding all load forecasts has been shared in-confidence with the AER in its role of overseeing the RIT-T and ensuring the efficiency of any ultimately proposed expenditure.

Overall, in preparing this PACR (and the initial PACR), we have engaged with load proponents on the commitment status for key potential loads. Specifically, we have sought to corroborate the forecasts provided by proponents through having them provide additional information as to how each load is considered to meet the RIT-T criteria for being considered ‘committed’ or ’anticipated’. In a number of instances, we have relied on how Essential Energy have treated, or suggest treating, particular loads based on their more detailed understanding of the commitment status of these loads. Both processes have been instrumental in how each potential load has been factored into the analysis, as outlined in the table below.

Table C. 1 – Additional detail on the basis for including forecast spot loads in the assessment

Load	Load area	Included in the low demand forecast?	Included in the central demand forecast?	Included in the high demand forecast?	Number of RIT-T criteria for ‘committed’ or ‘anticipated’ met	Comment
Confidential mining load	Orange	Yes	Yes	Yes	Five[79]	The increase in this confidential mining load is considered a committed project. The load increase included in the low demand forecast has been provided by Essential Energy (from their DAPR 2021 demand forecast). The load increase included in the central and high demand forecasts is from the proponent’s forecast (and, specifically, the low value of their forecast has been used). The proponents medium and high forecasts have been considered as a sensitivity only, refer section 7.5.1.
Confidential mining load	Parkes	Yes	Yes	Yes	N/A (included based on Essential Energy forecast – see comment)	This confidential load increase is considered a committed project and forecasted demand growth within the next 10 years is from the Essential Energy 2021 DAPR demand forecast (and is reflected in the same way in each of the low, central and high demand forecasts).

[79] All five criteria have been met for the load included in the low value of the forecast from the proponent. Therefore, we have included the low value of the proponent’s forecast in the low, central and high demand forecasts in this assessment. A higher demand forecast provided by the proponent has not been included in any of the demand forecasts in the core scenarios for this assessment. However, we have investigated a sensitivity in which a higher demand forecast from the proponent is included in the assessment (see section 7.5.1).

Load	Load area	Included in the low demand forecast?	Included in the central demand forecast?	Included in the high demand forecast?	Number of RIT-T criteria for 'committed' or 'anticipated' met	Comment
Parkes SAP	Parkes	Yes	Yes	Yes	N/A[80] (included based on advice from the proponent that the enabling infrastructure is in delivery and progressing on program for completion in 2023.)	The Parkes SAP is considered anticipated load. The central demand forecast was obtained from the proponent. A demand forecast for the low forecast was formed by scaling down the central demand forecast. The high demand forecast peak is assumed to be 70 per cent of the peak provided by the proponent (and scaled down for earlier years).
McPhillamys Mine	Panorama	No	Yes	Yes	N/A (included based on Essential Energy forecast – see comment)	McPhillamys Mine is considered an anticipated project. Its load was not included in the low demand forecast. The central demand forecast assumed 70% of the load, with the full amount included in the high demand forecast. The high demand forecast reflects values from Essential Energy's forecast.
Sunrise Mine	Parkes	No	Yes	Yes	Met or in the process of meeting at least three criteria.	Sunrise Mine is considered an anticipated project. Its load was not included in the low demand forecast. The central demand forecast assumes 70% of the load, with the full amount included in the high demand forecast. The high demand forecast reflects values from Essential Energy's forecast.

80 The RIT-T criteria apply to individual spot loads. The Special Activation Precinct consists of multiple projects installed at a distribution level development. The RIT-T criteria cannot be applied to these types of complex loads.

Load	Load area	Included in the low demand forecast?	Included in the central demand forecast?	Included in the high demand forecast?	Number of RIT-T criteria for 'committed' or 'anticipated' met	Comment
Confidential mining load	Confidential	No	No	Yes	N/A (included based on Essential Energy advice through the joint planning process)	This confidential mining load is considered an anticipated project. Its forecast demand is only included in the high demand forecast.
Confidential mining load	Parkes	No	No	Yes	Four[81] (included based on Essential Energy advice through the joint planning process)	This confidential mining load is considered an anticipated project. Its forecast demand is only included in the high demand forecast.

[81] While four out of five criteria have been met, our detailed review indicated that this load should be included only in the high demand forecast.

Appendix D Additional detail on the methodology used to estimate capital costs

Our cost estimates for all credible options presented in this amended PACR (and the initial PACR) have been prepared in accordance with the Augmentation Expenditure ('Augex') Overview Paper submitted with our 2023-28 Revenue Proposal.[82] Section 7 of that paper outlines in detail our forecasting method, inputs, models and assumptions, including on unit costs, cost escalation and overheads (see sections 7.6, 7.7 and 7.8 of the Revenue Proposal Augex Overview Paper).

In summary, the cost estimates are developed using our 'MTWO'[83] cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (ie, there is an equal likelihood of over- or under-spending the estimate total). In accordance with industry best practice, the cost estimates consist of a base estimate and a P50 allowance lump sum.

For an Option Feasibility Studies (OFS) cost estimate, which is the level of estimate used in this PACR, the level of scope development and maturity of design inputs results in a cost estimate with an accuracy of +/-25 per cent. This is consistent with our Prescribed Capital Investment Process, which has been provided to the AER as part of the PIAC dispute process (along with a range of other confidential material relating to the cost estimation process). An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in real, 2020-21 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates did not include or forecast any real cost escalation for materials.

Biodiversity costs and property allowances for transmission lines apply when an option requires a new easement and use of an existing easement that is modified does not require these costs. Biodiversity and property costs have therefore been included for the new lines between Orange and Orange North (Options 1A/1B, 1C, 4 and 6) but are not present in the costs of the other options (such as Option 3). The Wellington to Parkes line common between Options 1A/1B and Option 3 do not require biodiversity and property costs, as they would be built on existing easements. Biodiversity costs and property allowances have been estimated by subject matter experts who assess the transmission line locality, property market and environment to estimate a per kilometre rate for the transmission line easement which is used in the capital cost estimate.

While some component costs presented in Section 4 of this PACR include land costs and biodiversity offset costs, they have not been broken out separately to contain the table. However, the NPV model released alongside the PACR separates out these elements.

82 Available at: https://www.aer.gov.au/system/files/TransGrid%20-%20Augex%20Overview%20Paper%20-%2031%20Jan%202022-%20PUBLIC.pdf

83 MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built upon a bespoke vertical cloud infrastructure supplied by Microsoft Azure, MTWO allows users to integrate and digitalise all project delivery processes in a complete end-to-end solution. More than 100 enterprise-wide modules are built into MTWO, with everything from 5D BIM virtualisation to scheduling, procurement, bidding and tendering on offer. RIB's iTWO cx project management software is also available as part of the MTWO solution.

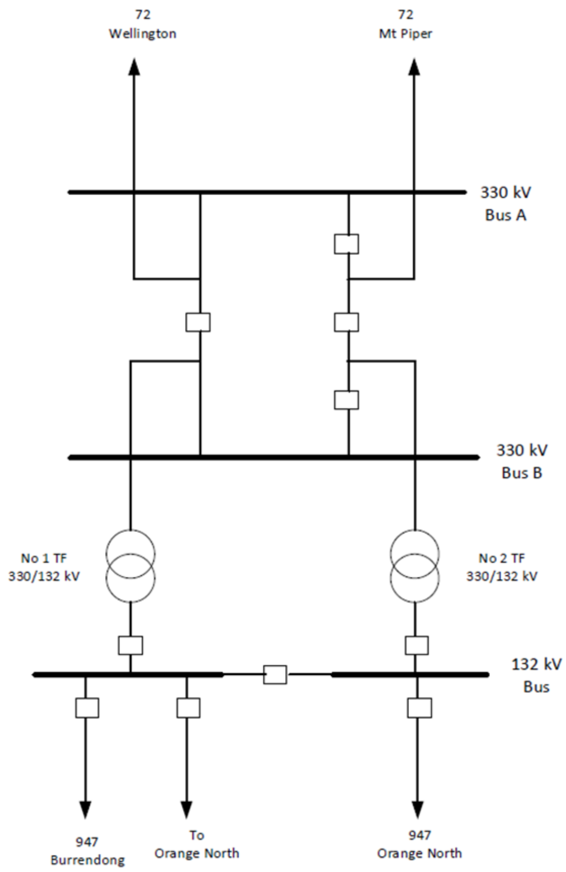
Appendix E Indicative line diagrams for each option

This appendix provides the line diagrams for each of the network elements of credible options considered in this PACR, as relevant. Existing elements are shown in black, while new elements are shown in red for all figures except Figure C-1 (since all elements are new and so have been presented as black for a neater presentation).

Option 1A/1B – New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)

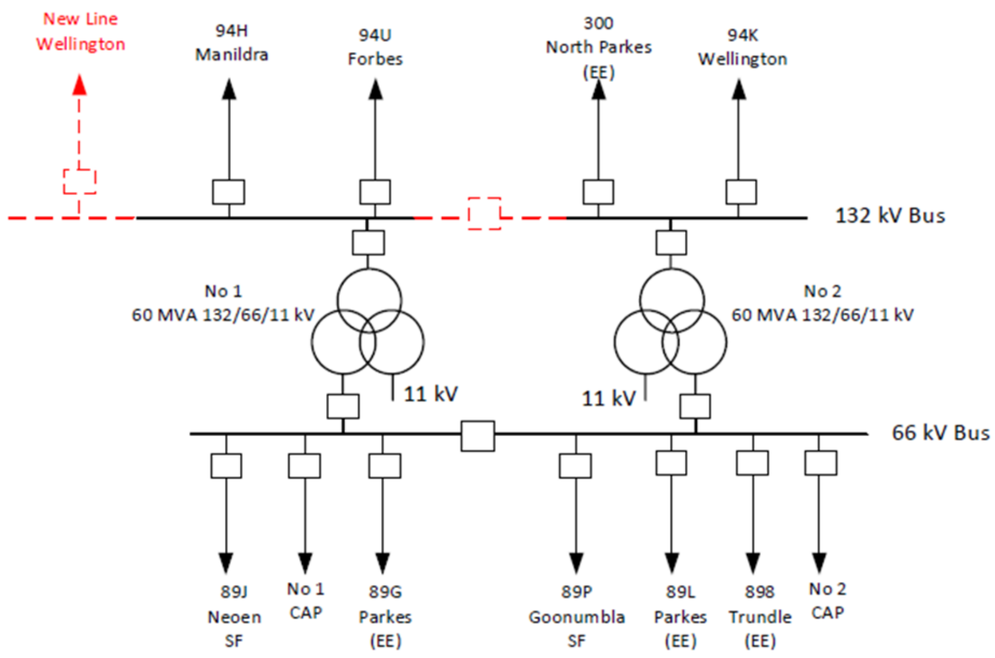
The indicative layout for the Orange 132/66 kV substation under Option 1A/1B is shown in Figure E-1 below.

Figure E-1: Indicative Orange new 330/132 kV substation layout under Option 1A/1B



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 1A/1B is shown in Figure E-2 below.

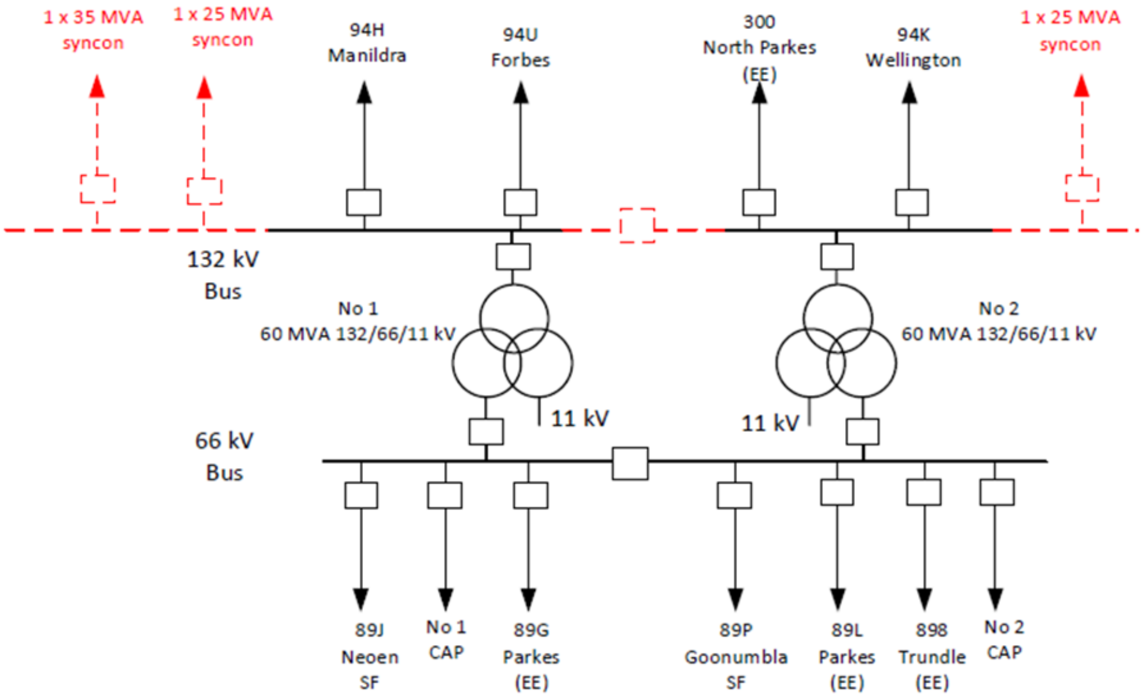
Figure E-2: Indicative Parkes 132/66 kV substation layout under Option 1A/1B



Option 1C – Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)

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

Figure E-3: Indicative Parkes 132/66 kV substation layout under Option 1C

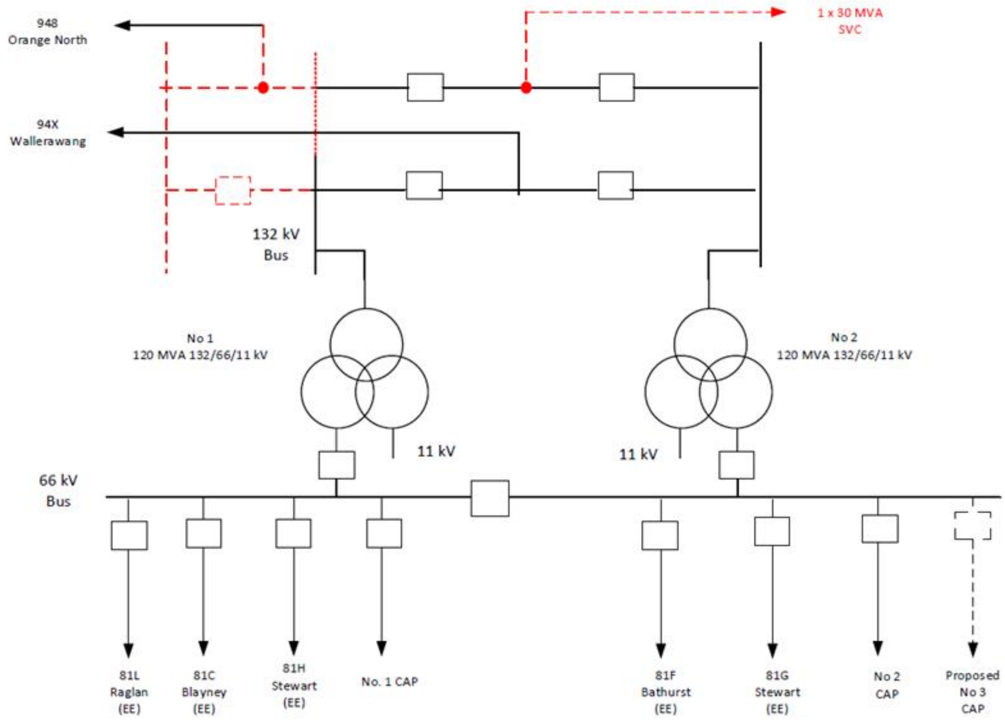


The indicative ultimate layout for the new Orange 330/132 kV substation under Option 1C is the same as that set out for Option 1A/1B in Figure E-1 above.

Option 3 – Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)

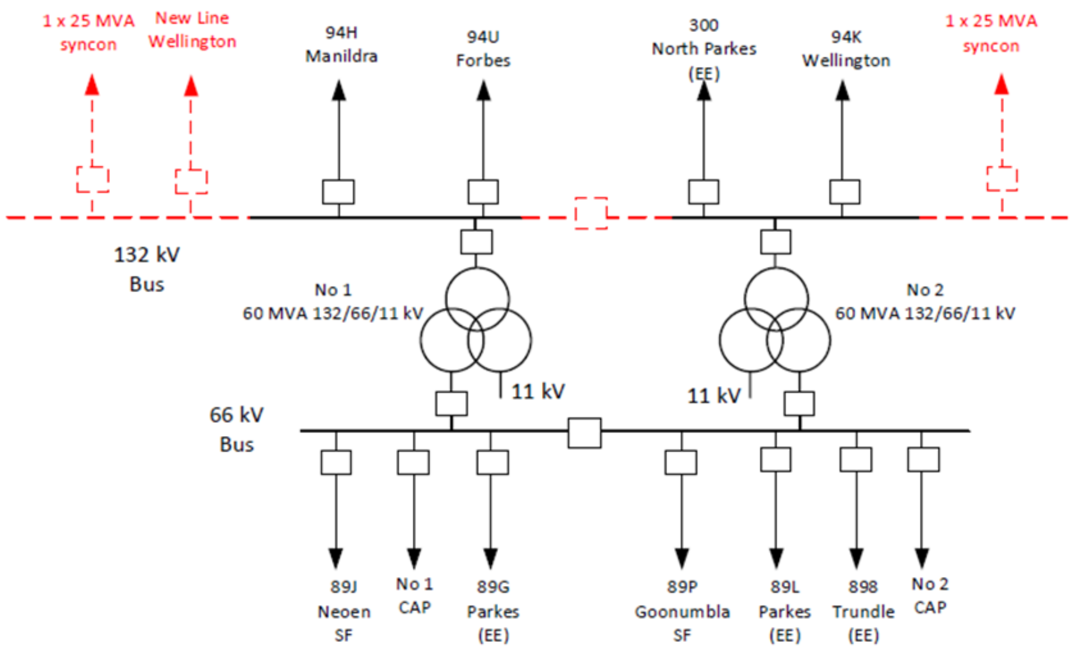
The indicative ultimate layout for the Panorama 132/66 kV substation under Option 3 is shown in Figure E-4 below.

Figure E-4: Indicative Panorama 132/66 kV substation layout under Option 3



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 3 is shown in Figure E-5 below.

Figure E-5: Indicative Parkes 132/66 kV substation layout under Option 3



Option 4 – Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

The indicative ultimate layout for the Panorama 132/66 kV substation under Option 4 is the same as for Option 3 shown in Figure E-4 above.

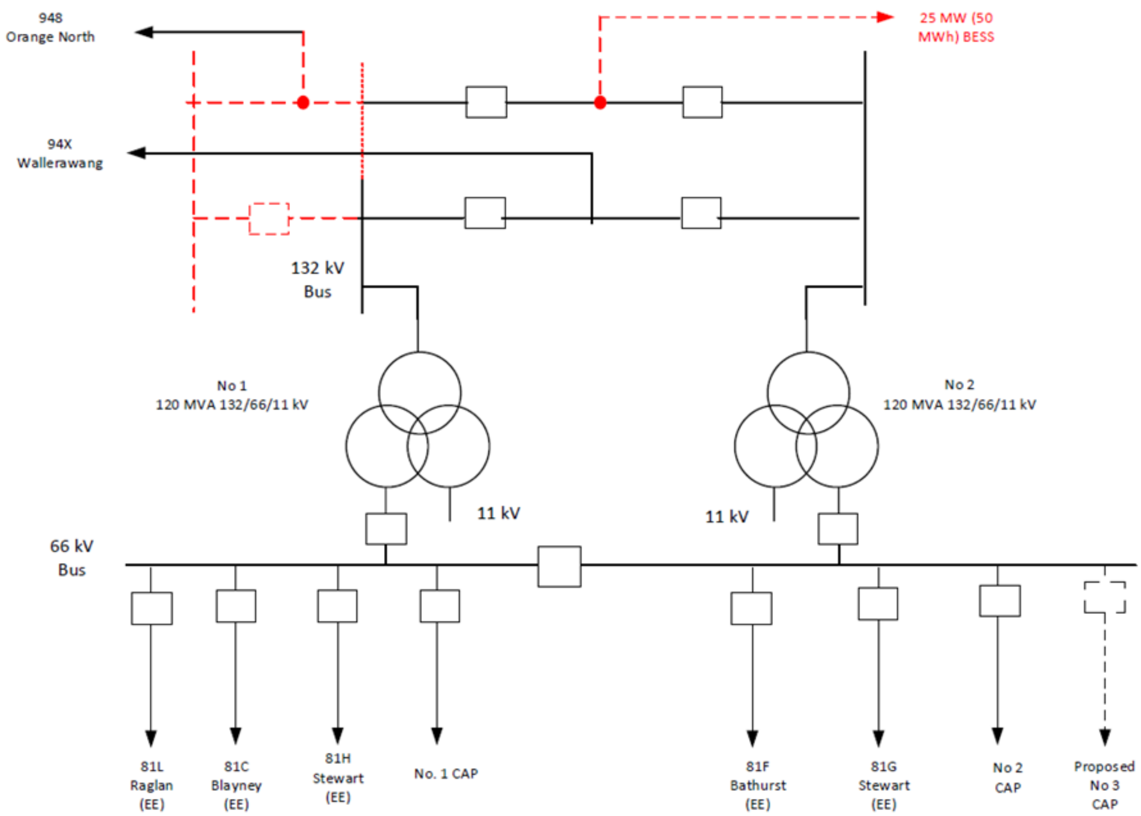
The indicative ultimate layout for the Parkes 132/66 kV substation under Option 4 is the same as for Option 1C shown in Figure E-3 above.

The indicative ultimate layout for the new Orange 330/132 kV substation under Option 4 is the same as for Option 1A/1B shown in Figure E-1 above.

Option 5 – Batteries at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)

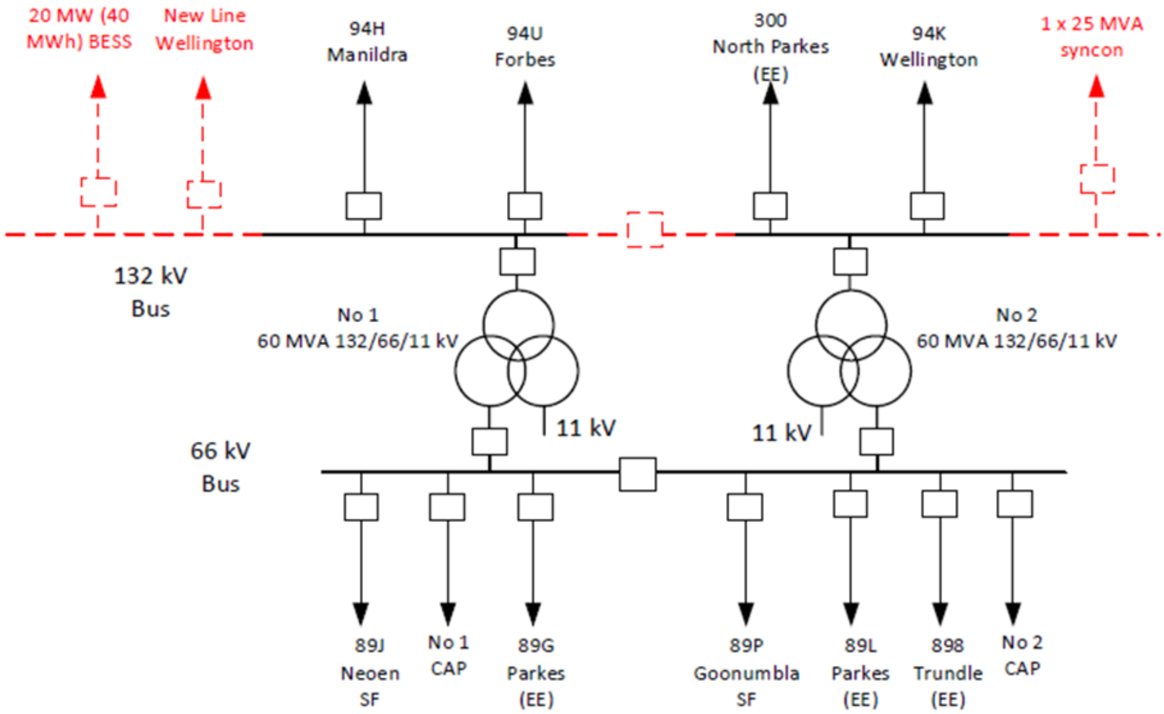
The indicative ultimate layout for the Panorama 132/66 kV substation under Option 5 is shown in Figure E-6 below.

Figure E-6: Indicative Panorama 132/66 kV substation layout under Option 5



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 5 is shown in Figure E-7 below.

Figure E-7: Indicative Parkes 132/66 kV substation layout under Option 5

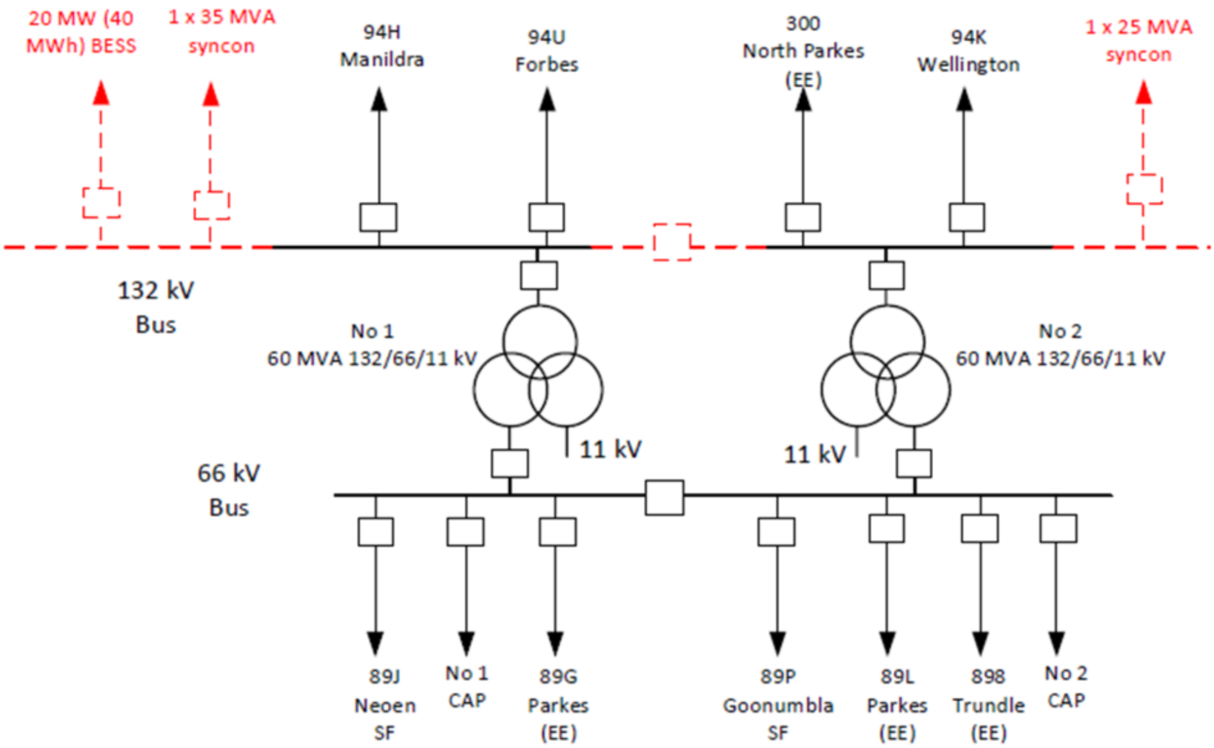


Option 6 – Batteries at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

The indicative ultimate layout for the Panorama 132/66 kV substation under Option 6 is shown in Figure E-6 above.

The indicative ultimate layout for the Parkes 132/66 kV substation under Option 6 is shown in Figure E-8 below.

Figure E-8: Indicative Parkes 132/66 kV substation layout under Option 6



An indicative ultimate layout for the new Orange 330/132 kV substation under Option 6 is shown in Figure E-1 above.

Appendix F Overview of the wholesale market modelling undertaken

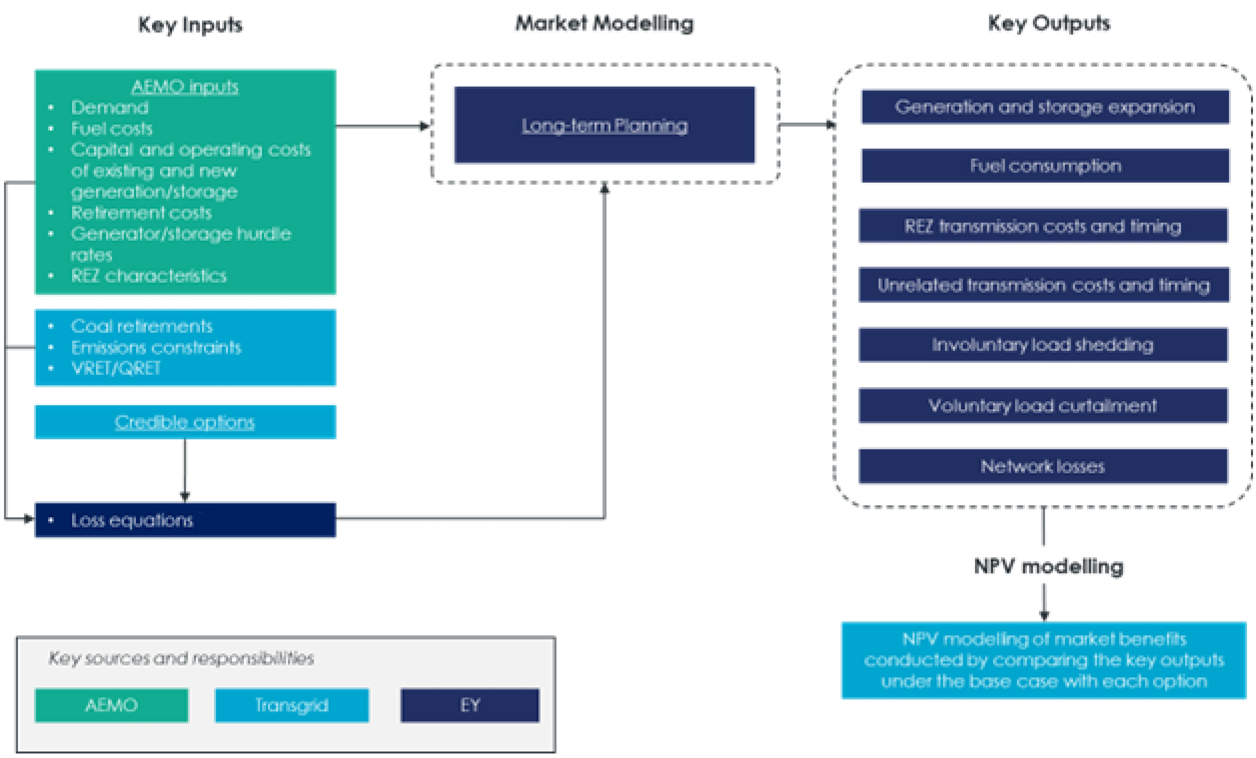
As outlined in the body of this PACR, we have engaged EY to undertake the wholesale market modelling as part of this PACR (which has not been amended since the initial PACR).

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 reserve 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.

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

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



** As outlined in section 6.2, the avoided involuntary load shedding in the central west 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).[84]

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 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.

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

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.

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 F-1: PACR modelled scenario key drivers input parameters

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ESOO 2021 (draft ISP 2022) – Step Change	ESOO 2021 (draft ISP 2022) – Progressive Change	ESOO 2021 (draft ISP 2022) – Hydrogen Superpower
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook – Step Change	2021 Inputs and Assumptions Workbook – Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook – Step Change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook – Progressive Change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook – Hydrogen Superpower In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook – Step Change Lewis Grey Advisory 2020, Step Change	2021 Inputs and Assumptions Workbook – Progressive Change Lewis Grey Advisory 2020, central	2021 Inputs and Assumptions Workbook – Hydrogen Superpower Lewis Grey Advisory 2020, Step Change
Coal fuel cost	2021 Inputs and Assumptions Workbook – Step Change Wood Mackenzie, Step Change	2021 Inputs and Assumptions Workbook – Progressive Change Wood Mackenzie, central	2021 Inputs and Assumptions Workbook – Hydrogen Superpower Wood Mackenzie, Step Change
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook – Step Change 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook – Progressive Change 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – Hydrogen Superpower 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50 % by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200 % Renewable generation by 2040		
NSW Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the draft 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	Draft 2022 ISP – EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP – Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP – Step Change: HumeLink commissioned by July 2028	Draft 2022 ISP – Progressive Change: HumeLink commissioned by July 2035	Draft 2022 ISP – Hydrogen Superpower: HumeLink commissioned by July 2027
Marinus Link	Draft 2022 ISP –1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	Draft 2022 ISP – VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 ISP – QNI minor commissioned by July 2022		
QNI Connect	Draft 2022 ISP – Step Change: QNI Connect commissioned by July 2032	Draft 2022 ISP – Progressive Change: QNI Connect commissioned by July 2036	Draft 2022 ISP – Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP – Step Change: VNI West commissioned by July 2031	Draft 2022 ISP – Progressive Change: VNI West commissioned by July 2038	Draft 2022 ISP – Hydrogen Superpower: VNI West commissioned by July 2030
Victorian SIPS	Draft 2022 ISP – 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.		

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
New-England REZ Transmission	Draft 2022 ISP – Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, and New England REZ Extension commissioned by July 2031
Snowy 2.0	2021 Inputs and Assumptions Workbook – Snowy 2.0 is commissioned by December 2026		

Appendix G Summary of consultation on the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process, besides those raised in confidential submissions.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PACR, unless otherwise stated.

Table G. 1: Summary of consultation on the PADR

Summary of comment(s)	Submitter(s)	Our response
Use of non-network solutions to address voltage constraints		
The CNSWJO emphasised the importance of energy security for the region and suggested that, arguably, the revision of the credible options from the PSCR to the PADR had focussed on facilitating the REZ at the expense of broader energy security.	Central New South Wales Joint Organisation (CNSWJO), p. 3	The change in credible options between the PSCR and the PADR reflected both submissions to the PSCR and EOI (resulting in four new options being included that utilise non-network technologies put forward by third-party proponents) and revised demand forecasts since the PSCR (which led to the network elements being resized and rescoped). The revision in the credible options since the PSCR has not involved a consideration of REZ connections as suggested by the CNSWJO. All options in the PADR, and now PACR, are considered able to meet the Cadia load included in the demand forecasts, as outlined in section 4. The high Cadia forecast is not currently considered certain enough, when assessed against the RIT-T criteria for 'committed' and 'anticipated', to be included in the core demand forecasts used in this PACR. Hence, we have not reflected all demand forecasts provided by Cadia in the RIT-T assessment.
Demand forecasts		
Ensuring that mining loads are accounted for in demand forecasts		
The PSCR referenced particular mine loads and specific load forecasts for Parkes SAP, whereas these were not specifically mentioned in the PADR.	CNSWJO and Parkes Shire Council, p. 6	See section 3.3.

Summary of comment(s)	Submitter(s)	Our response
Ensuring that regional growth and proposed developments are appropriately accounted for in demand forecasts		
PIAC is concerned that demand forecasts based on regional growth plans may not be met, and recommends any projected demand relating to regional growth plans should be based on an independent assessment that takes into account the actual approved and/or financially committed developments.	PIAC, p. 1	In preparing the PACR, we have engaged further with load proponents on the commitment status for key potential loads. Specifically, we have liaised directly with each proponent to determine whether the loads are considered 'committed'/ 'anticipated' under the RIT-T, i.e., whether they meet the criteria for 'committed' or 'anticipated' under the RIT-T. All demand forecasts are considered in-line with industry best practices and take into account the types of drivers CNSWJO have listed.
Significant growth and development is expected in the Bathurst, Orange and Parkes region. Local government stakeholders are concerned that growth assumptions in the PADR for the eastern part of the region for both industry and population are underestimated, and that energy security may be compromised. Assumptions used should reflect actual regional population growth, residential fuel switching, transport electrification and manufacturing growth.	CNSWJO and Parkes Shire Council, pp. 1-2, 10-11	
Other demand related points		
The PADR refers to only voltage constraints (not thermal constraints) and does not detail whether the constraint is voltage above 10 per cent nominal or voltage below 10 per cent nominal under foreseeable conditions.	CNSWJO and Parkes Shire Council, p. 6	While the PSCR identified thermal constraints in the area if action is not taken, particularly during times of low renewable generation dispatch in the region, demand forecasts reduced prior to publishing the PADR and our updated planning studies no longer forecast thermal constraints over the planning horizon of this RIT-T. The voltage constraint is due to under-voltage.
Estimating the market benefits of the options		
Development of reasonable scenarios		

Summary of comment(s)	Submitter(s)	Our response
The wholesale market modelling should be updated to reflect AEMO's Step Change scenario given the development of environmental and geopolitical factors around the world.	CNSWJO and Parkes Shire Council, pp. 7-8	The market modelling for the PACR has been updated to explicitly model each of the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 ISP, adopting the 2021 IASR assumptions – see section 2.3.4.
PIAC expressed a view that the high benefits scenario should not be included in the analysis due to unrealistic assumptions (25 per cent lower network capital costs, a high VCR estimate, and a low discount rate of 2.23 per cent).	PIAC, p. 1	The purpose of using a high benefits (and low benefits) scenario was to test the rankings of options against an extreme bound of plausible economic benefits. However, this has now been revised in light of the AER dispute determination. See section 5.1.
PIAC recommends a more realistic approach of applying 50 per cent weighting to each of the central and low net economic benefits scenarios.	PIAC, p. 2	The scenario weights have been updated since the PADR to reflect those used in the 2022 ISP (which has the effect of reducing the weighting of the high scenario). See section 5.2.
Additional benefits of non-network solutions		
Options 7A and 7B will create additional jobs in the region, and should be preferred over Option 7D with no material difference in net market benefits between the options.	CNSWJO and Parkes Shire Council, p. 10	While we note these expected real sources of benefit, they are not able to be captured in the RIT-T analysis due to it being a cost-benefit assessment focussed on 'all those who produce, consume and transport electricity in the market' and the benefits like job creation are considered 'externalities' under the RIT-T.
Proposed new options or modifications to existing options		

Summary of comment(s)	Submitter(s)	Our response
A range of variants to building a direct 132 kV line from Wellington to Parkes have been proposed including alternate routes, building a dual circuit line, and building the line at 330 kV. These variants would offer capacity, voltage and reliability benefits to the Central West network and Parkes region. Extending the 330 kV network offers significant advantages beyond the Bathurst, Orange and Parkes region.	CNSWJO and Parkes Shire Council, p. 10	See section 3.4.
Potential synergy with the Neoen wind farm at Alectown should be considered.	Parkes Shire Council, p. 1	See section 3.3.

Transgrid

People. Power. Possibilities.

NSW Electricity Networks Operations Holdings Pty Limited (ACN 609 169 959),
as trustee for NSW Electricity Networks Operations Trust (ABN 70 250 995 390).
Registered business name is TransGrid (ABN 70 250 995 390).