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

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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.

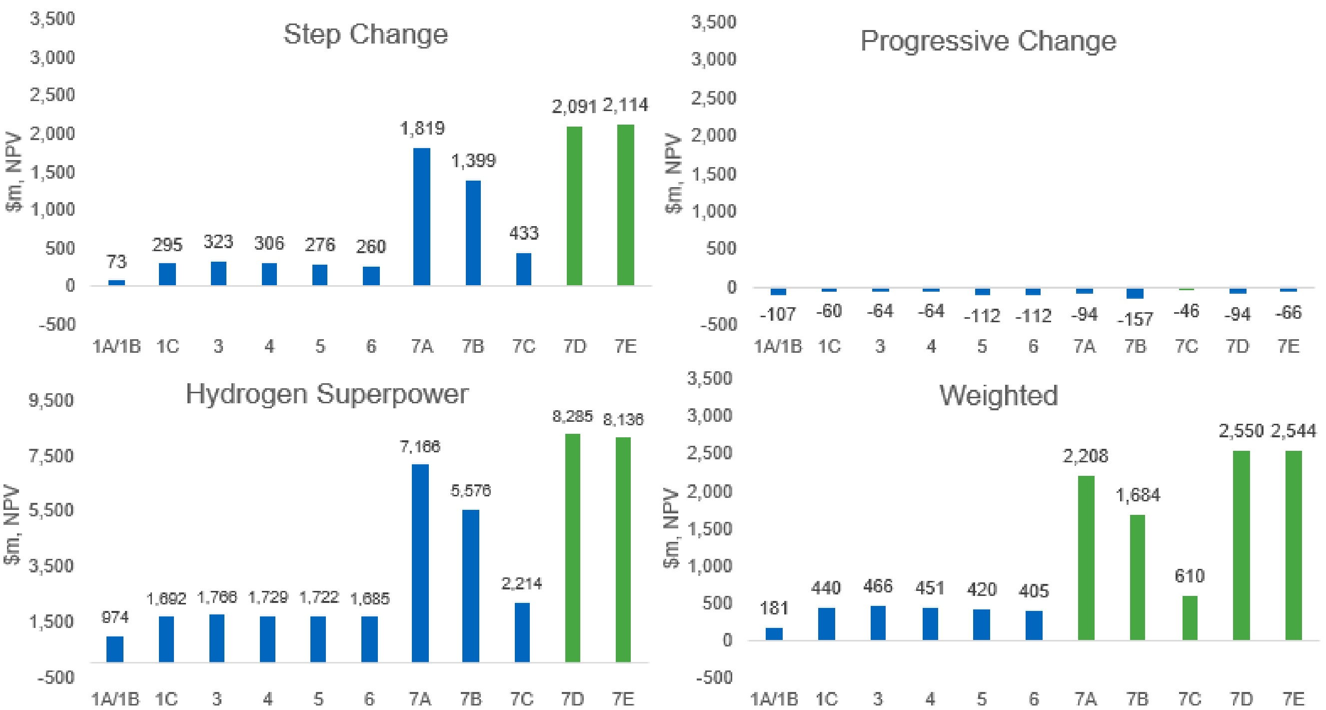
We have also investigated the sensitivity of the results to alternate weightings as part of this PACR (and they are found not to be sensitive).

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.