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Increasing capacity for generation in the Molong and Parkes area

RIT-T Project Assessment Conclusions Report

Region: Central West NSW

Date of issue: 31 October 2023

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for improving capacity for renewable generation in the Molong and Parkes area. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process following the Project Assessment Draft Report (PADR) we published on 16 June 2023.

The Molong and Parkes area has seen significant growth in renewable generation connections to the transmission network, as part of the wider energy market transition. New renewable generators have connected or are planning to connect to the network west of our Molong 132/66 kV substation. Nineteen solar and wind generation farms in the area with a combined output of 1,273 MW are already in service, with a further 1,148 MW of generation committed or anticipated at the time the PADR was published. Since the publication of the PADR, an additional 1,250 MW of committed and anticipated wind and solar generation capacity has been added in the Molong and Parks area.

Line 94T plays a central role in transmitting the electricity from these renewable generators in the Molong and Parkes area to the load in Orange. It connects Molong substation to Orange North switching station, which in turn supplies Orange city, Cadia Mine and surrounding areas.

The current rating of the 132 kV Line 94T (Molong – Orange North), is constraining renewable generation in the Molong and Parkes area. AEMO's monthly constraint reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM). Network modelling shows thermal overloading of Line 94T is expected under normal system conditions with the current level of in-service and committed generation dispatched to their maximum capacities. Hence, we have identified the opportunity to strengthen the transmission network to relieve this constraint and realise net market benefits by avoiding curtailment of low-cost renewable generation in the Molong and Parkes area.

Benefits from improving capacity and relieving existing constraints in the Molong and Parkes area

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

Within the context of the RIT-T assessment, greater output from renewable generation is expected to deliver market benefits primarily through reductions in total dispatch costs from:

- lower fuel costs, by enabling low-cost renewable generation to displace higher cost conventional generation elsewhere; and
- lower capital costs, by reducing (or deferring) the need for new investment in generation plants.

We consider this a 'market benefits' driven RIT-T as opposed to a 'reliability corrective action' driven RIT-T. The additional wholesale market benefits associated with each credible option have been estimated using market modelling as part of this PACR.

The PACR analysis has benefited from stakeholder consultation

We published a PADR on 16 June 2023 and invited written submissions on the material presented within the document.

Three submissions were received in response to the PADR. The main topics that emerged from the submissions were:

- Additional renewable generation in the Molong and Parkes area
- Implementation timing for the preferred option
- Options to address potential constraints in other parts of the central west NSW network
- Inconsistency between reported line ratings in the EY market modelling and Transgrid PADR.

The key matters raised in submissions relevant to the RIT-T assessment, as well as our responses and how the matters raised have been reflected in the PACR assessment, are summarised in Section 3 and Appendix B.

Key developments since the PADR have been reflected in the PACR

There have been three notable developments since the PADR was released, which impact the analysis in this RIT-T. In particular:

- AEMO released the 2023 Inputs, Assumptions and Scenarios Report (IASR) on 28 July 2023
- AEMO released an updated database of committed and anticipated generation projects in the NEM in July 2023.
- AEMO released the 2023 Electricity Statement of Opportunities (ESOO) in August 2023.

Details of these changes are provided in Section 2.2. We do not consider these developments will impact the relative ranking of the options as presented in the PADR.

The credible options remain unchanged from the PADR

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

Table E-1: Summary of the credible options

Option	Description	Estimated capex (June $2022 million)
1	Increase transmission line design temperature of Line 94T	1.41
2	Restring Line 94T with higher rated ‘Flicker/ACSS’ conductor on existing structures	7.50
2A	Restring Line 94T with higher rated ‘Partridge/ACSS/HS285’ conductor on existing structures	8.16
2B	Implementing Option 2 together with power flow controllers	25.97
3	Replacing Line 94T with a double circuit transmission line	38.54

Option	Description	Estimated capex (June $2022 million)
4	Installation of a 50MW/300MWh BESS at Molong substation	185.69

* All estimated capex (+/- 25%)

Uncertainty has been captured by way of three scenarios

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

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted (‘expected’) net benefit. It is this ‘expected’ net benefit that is used to rank credible options and identify the preferred option. The credible options have been assessed under three scenarios as part of this PACR assessment, which reflect the scenarios from AEMO’s 2022 ISP.

Table E-2 summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table E-2: Summary of scenarios

Variable	Step Change	Progressive change	Hydrogen Superpower
Capital costs	Base estimate	Base estimate	Base estimate
Demand	Central demand forecast (ISP POE10 and Orange North POE50)	Central demand forecast (ISP POE10 and Orange North POE50)	High demand forecast (ISP POE10 and Orange North POE10)
New renewable generation in the area	All in-service, committed and anticipated generators (as outlined in section 2.2)	All in-service, committed and anticipated generators (as outlined in section 2.2)	All in-service, committed and anticipated generators (as outlined in section 2.2)
Wholesale market benefits estimated	EY estimate based on the ‘step change’ 2022 ISP scenario	EY estimate based on the ‘progressive change’ 2022 ISP scenario	EY estimate based on the ‘hydrogen superpower’ 2022 ISP scenario

The three scenarios have been weighted based on the ISP weightings:

- 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.

Option 2 is found to be the preferred option

This PACR finds that Option 2 is the preferred option for meeting the identified need on a weighted basis and in all but one of the sensitivities assessed. This option involves increasing Line 94T’s summer daytime thermal rating by restringing Line 94T with a higher capacity conductor. The thermal rating of the new conductor would increase from 112 MVA to at least 150 MVA.

In the Project Assessment Draft Report (PADR) we identified Options 2 and 2A as the preferred options. We have decided to progress with Option 2 over Option 2A as Option 2 is expected to deliver approximately $24.5 million in net benefits over the assessment period (on a weighted-basis), which is marginally higher than the $23.9 million in net benefits expected to be delivered by Option 2a.

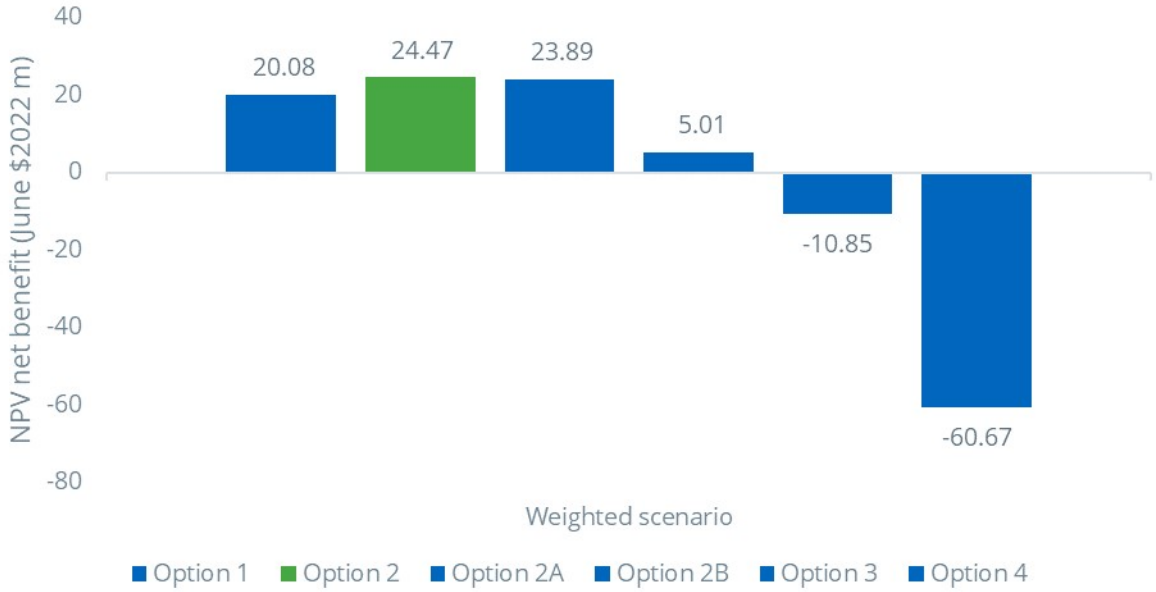
While other options, such as Option 4, are able to generate additional gross market benefits compared to Option 2, the build costs of these options are significantly higher and result in lower net benefits under all scenarios.

Option 2 will now be subject to detailed design. If, during the detailed design stage, another conductor with the same or higher rating and similar costs and benefits as Option 2 is found to be more fit for purpose, we may amend the preferred option to use the alternative conductor. We will only adopt an alternative conductor if its use will not result in a material change to the net benefits of the option or a delay to when the option can be implemented, and subject to updating stakeholders on the proposed changes.

Table E-3: NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	20.08
Option 2	24.47
Option 2A	23.89
Option 2B	5.01
Option 3	-10.85
Option 4	-60.67

Figure E-1 NPV of net economic benefits relative to the base case (Weighted scenario, June $2022 million)



Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process.

Parties wishing to raise a dispute notice with the AER may do so prior 2 December 2023 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 days, after which the formal RIT-T process will conclude.

Further details on the RIT-T can be obtained from our Regulation team via regulatory.consultation@transgrid.com.au.[1] In the subject field, please reference ‘Increasing capacity for generation in the Molong and Parkes area PACR’.

[1] Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number

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for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

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1. Introduction

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for improving capacity for renewable generation in the Molong and Parkes area. Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process following the Project Assessment Draft Report (PADR) we published on 16 June 2023.

The Molong and Parkes area has seen significant growth in renewable generation connections to the transmission network, as part of the wider energy market transition. New renewable generators have connected or are planning to connect to the network west of our Molong 132/66 kV substation. Nineteen solar and wind generation farms in the area with a combined output of 1,273 MW are already in service, with a further 1,148 MW of generation committed or anticipated at the time the PADR was published. Since the publication of the PADR, an additional 1,250 MW of committed and anticipated wind and solar generation capacity has been added in the Molong and Parks area. Line 94T plays a central role in transmitting electricity from renewable generators in the Molong and Parkes area to the load in and around Orange. It is a 132 kV line that connects Molong substation to Orange North switching station, which in turn supplies Orange city, Cadia Mine and surrounding areas.

The current rating of Line 94T is constraining renewable generation in the Molong and Parkes area. The Australian Energy Market Operator's (AEMO's) Monthly Constraint Reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM). AEMO's latest Annual NEM Constraint Report for 2022 identified the Line 94T constraint as the second highest binding impact network[2]. Network modelling shows thermal overloading of Line 94T is expected under normal system conditions with current levels of in-service and committed generation dispatched to their maximum capacities.

We have identified the opportunity to realise net market benefits in the NEM by relieving this constraint and avoiding curtailment of low-cost renewable generation in the Molong and Parkes area. We consider this a 'market benefits' driven RIT-T and expect the preferred option to have positive net market benefits.

1.1. Purpose of this report

The purpose of this PACR is to:

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

[2] AEMO, *NEM Constraint Report 2022 summary data*, 24 May 2023.

- identify the preferred option of the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, this report provides transparency into the planning considerations for investment options to stabilise the central west NSW power system, and the associated market benefits. A key purpose of this PACR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

1.2. Next steps

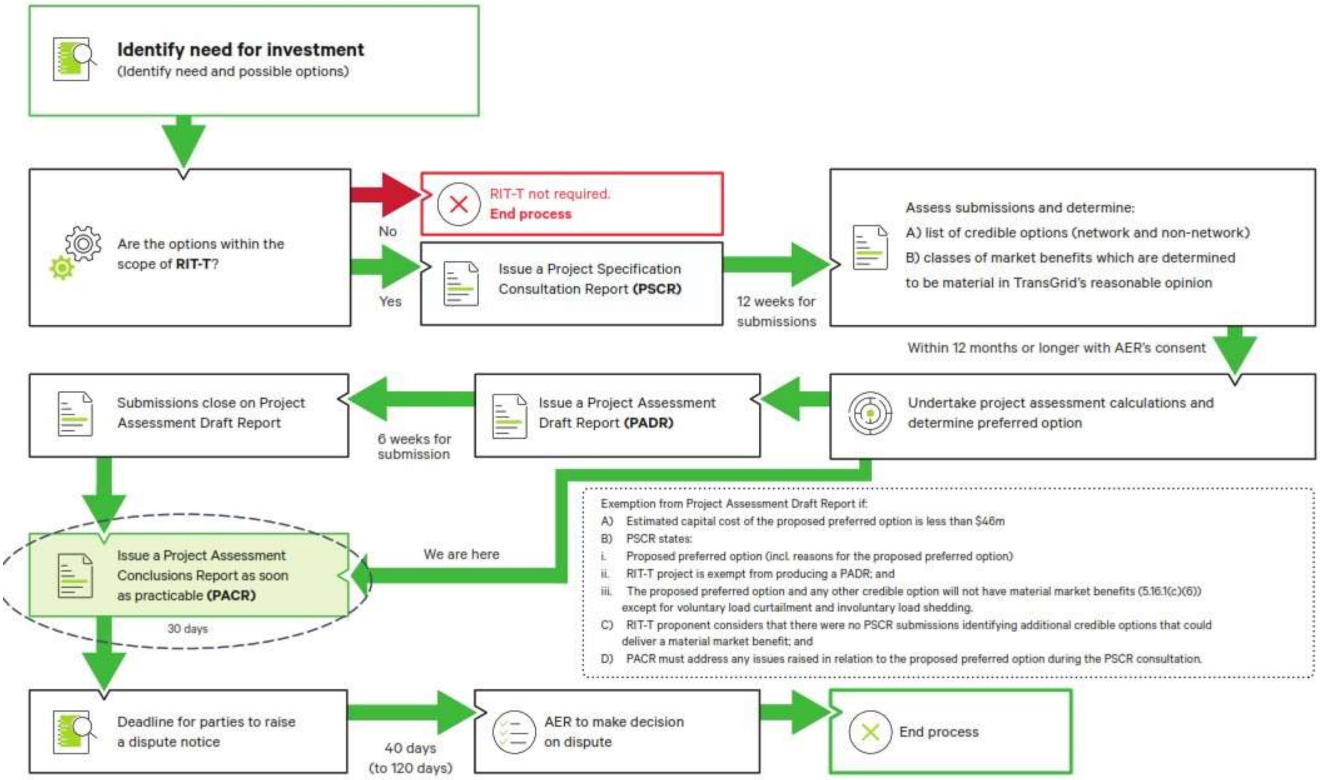
This PACR represents the final step of the consultation process in relation to the application of the RIT-T process.

The preferred option identified in this PACR is Option 2 (restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures). We will now proceed to a detailed design stage for this option prior to its implementation. If, during the detailed design stage, another conductor with the same or higher rating and similar costs and benefits as Option 2 is found to be more fit for purpose, we may amend the preferred option to use the alternative conductor. We will only adopt an alternative conductor if its use will not result in a material change to the net benefits of the option or a delay to when the option can be implemented, and subject to updating stakeholders on the proposed changes.

Parties wishing to raise a dispute notice with the AER may do so prior to 2 December 2023 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 120 days, after which the formal RIT-T process will conclude.

Further details on the RIT-T can be obtained from our Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Increasing capacity for generation in the Molong and Parkes area PACR'.

Figure 1-1 This PACR is the final stage of the RIT-T process



2. Benefits from increasing capacity in the Molong and Parkes area

This section discusses the ‘identified need’ for this RIT-T, before outlining the key developments that have occurred since the PADR was released in June 2023.

2.1. Summary of the identified need

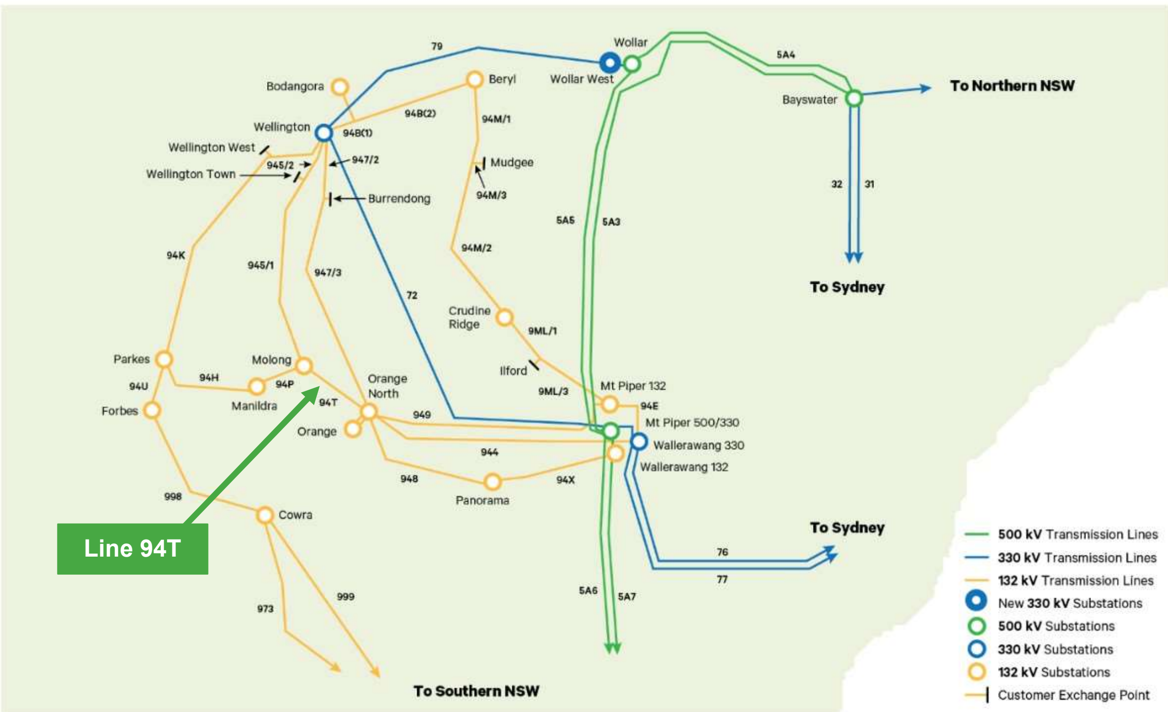
The identified need for this RIT-T is to increase consumer and producer surplus in the NEM through relieving network constraints on the supply of renewable generation from the Molong and Parkes area. This will enable a greater amount of renewable generation produced in the Molong and Parkes area to be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

Within the context of the RIT-T assessment, greater supply of renewable generation is expected to deliver market benefits primarily through reductions in total dispatch costs from:

- lower fuel costs, by enabling lower cost renewable generation to displace higher cost conventional generation elsewhere in the NEM; and
- lower capital costs, by reducing (or deferring) the need for new investment in generation plants to meet growing electricity demand in the future.

Line 94T is a 132 kV transmission line which connects our Molong 132/66 kV substation to our Orange North 132 kV switching station. It plays a central role in transmitting electricity from renewable generators in the Molong and Parkes area to load in and around Orange.

Figure 2-1 Location of Line 94T on our Central West transmission network



However, the combination of increasing demand in the Orange area and increasing renewable generation west of Molong substation is giving rise to binding constraints on the line. The constraint is caused by the existing 112 MVA (summer daytime) thermal capacity limit of Line 94T being reached during times of high renewable generation output. In these situations, thermal overloading of the 132 kV Line 94T can occur which constrains the amount of renewable generation that can be supplied from the Molong and Parkes area to load in the Orange area. Expected increases in renewable generation capacity in the Molong and Parkes area, and expected growth in demand in the Orange area, will result in the network constraint binding more often and to a greater extent.

This resulted in AEMO introducing operational constraints in the NEM Dispatch Engine (NEMDE) to limit power flows in order to manage the risk of thermal overload on Line 94T. AEMO's Monthly Constraint reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM), and AEMO's latest Annual NEM Constraint Report for 2022 identified the Line 94T constraint as the second highest binding impact network.[3]

If the constraint caused by the existing 112 MVA (summer daytime) thermal capacity limit of Line 94T is not addressed by a technically and commercially feasible credible option, the output curtailment of low-cost renewable generation in the Molong and Parkes area will increase. This curtailment will mean that a substantial quantity of low-cost renewable energy will not be available to displace higher-cost alternative energy generation within the NEM. It may also require additional generation capacity to be installed to meet demand growth in the Orange area, imposing additional costs on users.

2.2. Developments since the PADR

There have been three key developments since the PADR was released:

- AEMO released the 2023 IASR on 28 July 2023;
- AEMO released an updated database of committed and anticipated generation projects in July 2023;
- AEMO released the 2023 ESOO in August 2023.

The 2023 IASR, 2023 ESOO, and the AEMO Generation information dated July 2023 include input assumption updates such as the central discount rate (increased from 5.5% to 7.0% for all scenarios); newly committed and anticipated plant; capital and fuel cost outlooks; federal and state renewable, emissions and storage policies; REZ limits and capacity factors, generator technical parameters and updated demand forecasts.

Considering the location and timing of the project and nature of the market modelling, assumptions such as the discount rate, renewable and storage policies, capacity factors, generator technical parameters, fuel cost, and emissions are less likely to impact the relative ranking of the options or the preferred option. This is because the main driver of the forecast gross market benefits of the options is the extent to which the constraint binding of Line 94T is alleviated by the option. Therefore, the key assumptions which may impact the gross market benefits of the Line 94T options are the demand forecast, generation capacity assumptions, and the REZ build limit in the Molong, Parkes, and Wellington area.

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3 AEMO, *NEM Constraint Report 2022 summary data*, 24 May 2023

In the 2023 IASR, AEMO identified an additional 1,250 MW wind and solar generation and about 25 MW/40 MWh of battery storage capacity as committed and anticipated in the Molong, Parkes, and Wellington area as listed in Table 2-1.

Table 2-1: Additional renewable generation in 2023 IASR compared to PADR assumptions - Molong, Parkes and Wellington area

Generating System	Connection location	Capacity (MW)	Status
Quorn Park Hybrid (battery)	Parkes	23.44 - 27.60 MW/40 MWh	Anticipated
Stubbo Solar Farm	Wellington	400 MW	Committed
Uungula Wind Farm	Wellington	414 MW	Anticipated
Wellington North Solar Farm (Lightsource)	Wellington	436.8 MW	Committed

In the PADR market modelling, a sensitivity case was conducted with an additional three generation units in the area (Stubbo Solar Farm, Uungula Wind Farm, and Wellington North Solar Farm) with a total capacity of 1,258 MW, which almost represents the additional committed and advanced capacity in the 2023 IASR in the Molong and Parkes area. The modelling outcomes of the three generators sensitivity scenario in the PADR did not change the relative rankings of the options.

In addition to the named generation above, the PADR market modelling undertaken for this RIT-T forecast that additional renewable and storage capacity will be built in the Central West Orana Renewable Energy Zone (CWO REZ). This varies with the ISP scenario being modelled, and is in excess of the committed and anticipated capacity by 2030 for all scenarios. Importantly, installed capacity does not vary significantly between the Base Case and all options. Consequently, committing additional capacity to the model to account for the recent changes in status of the projects above would be equivalent to moving the commissioning date of some of the generic plant in the model to an earlier date, but that would occur similarly for the Base Case and all options and therefore is not expected to change the relative ranking of the options.

The assumed wind and solar capacity build limit in the CWO REZ did not change significantly in the 2023 IASR relative to the 2022 ISP assumption applied in the Line 94T PADR modelling. This means the total amount of wind and solar capacity forecast to be built in this REZ would not be anticipated to change with re-simulation.

Overall, we believe re-simulation of the model to include additional generation capacity and updated CWO REZ build limits will not change the relative ranking of the options.

The 2023 ESOO demand forecast shows an increase in 10% POE demand forecast for NSW compared to the 2021 ESOO (consistent with the relevant scenarios in the ISP 2022 applied in the Line 94T PADR modelling). Modelling outcomes and analysis show that higher NSW demand is expected to reduce the frequency of binding of Line 94T due to a positive coefficient in the RHS of the Line 94T constraint equations. However, this will occur similarly across the Base Case and all options. Furthermore, the impact of increased NSW demand forecast in the 2023 ESOO would be mitigated by the fact that the assumed demand in the Orange area would not change with an update with the 2023 ESOO assumptions. This means applying the ESOO 2023 demand forecasts in the model is unlikely to significantly alter the relative benefits of the options. Considering the similarity of options 2 and 2A, the relative rankings of the preferred options are unlikely to be impacted. The PADR high load sensitivity of the demand forecast in the Orange area also shows that increased assumed demand in the area does not change the ranking of the options.

We consider additional modelling to account for the new assumptions is not required given that Option 2 is the preferred solution under all scenarios and for almost all sensitivities, and additional modelling would impose additional time and costs on a relatively small project. It would also delay the start of detailed design work on the preferred solution and potentially push back the delivery of the solution. As outlined in the RIT-T, Line 94T is currently one of the top binding constraints by impact on the network and any delay in delivering a solution will create additional costs to the market.

3. Consultation on the PADR

The PADR was released in June 2023. We received submissions from three parties to the PADR and have outlined some key points from these submissions below.

The main topics that emerged from the submissions were:

- Additional renewable generation in the Molong and Parkes area
- Implementation timing for the preferred option
- Options to address potential constraints in other parts of the central west NSW network
- Inconsistency between reported line ratings in the EY market modelling and Transgrid PADR.

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

3.1. Additional renewable generation in the Molong and Parkes area

One submission anticipates that renewable generation connections in the Molong and Parkes area will exceed what has been assumed in the PADR (i.e., a further 1,500 MW of planned wind and solar in the Molong and Parkes area). They are concerned that this will likely lead to network constraints re-emerging and require further capacity increases in the future.

While it is possible that additional capacity will be added to the Molong and Parkes area in the future, there is not yet sufficient certainty to include such potential future projects in our market modelling. This is consistent with the approach set out in the RIT-T guidelines, which requires only committed and anticipated generation to be included. It is worth noting that in addition to the named committed and anticipated generation, the PADR market modelling undertaken for this RIT-T forecast that additional renewable capacity will be built in the Central West Orana Renewable Energy Zone (CWO REZ) across all modelled scenarios and options. Details of the additional unnamed forecast generation capacity in the PADR model were provided in Table 2-2 of the PADR and shown in Table 3-1 again. Therefore, we do not expect that an additional 1,500MW of renewable generation capacity in the Molong and Parkes area will change the preferred option.

Table 3-1: Additional renewable generation built by the modelling associated with this RIT-T

ISP scenario	Additional capacity built in the CWO REZ
Step change	5.6 GW of wind and 5.3 GW of solar
Progressive change	5.4 GW of wind and 4.5 GW of solar
Hydrogen Superpower	4.8 GW of wind and 4.8 GW of solar

The PADR also included a sensitivity that increased renewable generation in the Molong, Parkes and Wellington area by a further 1,258 MW above AEMO’s committed and anticipated projects. The ranking of the options, and the preferred options, did not change under this sensitivity. We expect the same result under a scenario of 1,500MW of additional capacity.

3.2. Implementation timing for the preferred option

One submission considered that the proposed solution be commissioned no later than Q4 of 2025, which would allow the solution to be in place in time for the 2025/26 summer. It also considered that we consider implementing the preferred solution within a 12-month timeframe given the frequency of a binding constraint on Line 94T.

The timing of the preferred solution in this PACR is scheduled for 2025/26. This is in line with the stakeholder's suggested timing of no later than Q4 2025. We will consider further timing decisions as we undertake a more detailed design assessment of the preferred option following the conclusion of this PACR.

3.3. Options to address potential constraints in other parts of the central west NSW network

One submission considered that the PADR focused only on resolving the constraint on the 132 kV feeder 94T running between Molong and Orange North and that it failed to address the network constraints in the large high renewable energy resource region west of Bathurst. The submitter considered that low system strength in the Cowra, Parkes and Forbes area is causing declining marginal loss factors and curtailment in the area. In addition to the upgrade of Line 94T, the submission proposed developing a 330 kV line to Cowra substation to provide a long term solution to area constraints.

The identified need for this RIT-T is to increase consumer and producer surplus in the NEM through relieving network constraints on the supply of renewable generation from the Molong and Parkes area. This RIT-T is related to network overloading in the region and not a system strength (which is a network wide issue). System strength issues and potential network constraints in other parts of our network, are outside the scope of this RIT-T and have not been considered here.

Having said this, we are taking steps to identify and address network constraints and system strength issues in other parts of the network in central west New South Wales. This includes:

- The maintain reliable supply to the Bathurst, Orange and Parkes area (BOP) RIT-T[4], involves the use of a non-network solution provided via two new BESSs at Parkes and Panorama, potentially paired with the installation of other supporting technologies such as STATCOMs at synchronous condensers. 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 meeting system strength requirements in NSW RIT-T[5], which is currently at the Project Specification Consultation Report (PSCR) stage. It is seeking to provide the minimum and efficient levels of system strength forecast by AEMO at each of the NSW system strength nodes from 2 December 2025 (Wellington is the system strength node for the central west region). It also seeks to address a system strength shortfall declared by AEMO from 1 July 2025 to 1 December 2025 at Newcastle and Sydney West.

[4] Available at: https://www.transgrid.com.au/projects-innovation/bathurst-orange-and-parkes-supply
[5] Available at: https://www.transgrid.com.au/projects-innovation/meeting-system-strength-requirements-in-nsw

3.4. Inconsistency in the EY modelling and the reported line thermal rating in the PADR

One submission noted an inconsistency in the market modelling whereby EY had assumed that Option 2 and 2A would increase the thermal rating of Line 94T to 177 MVA and 152 MVA (Summer-day rating) respectively, but we had noted in the PADR that due to limitations on the line the effective rating for Option 2 would be limited to at least 150 MVA. The submission sought to ensure that the benefits of Option 2 and 2A are maintained when the thermal rating of the line is reduced to 150 MVA[6]

We have revised rating calculations for Option 2 and 2A, after publishing of PADR, and confirm that Summer-day rating of the line 94T is at least 152 MVA.

Our analysis indicates that the gross market benefits for Option 2 will not be materially reduced even when the thermal rating of the line is reduced to at least 152 MVA and the ranking of Option 2 and 2A will remain the same. This section describes our analysis.

The modelled thermal rating of Option 2A is less than Option 2 in all time periods. However, forecast gross market benefits of these options are very similar. This is because the gross market benefits of Options 2 and 2A are predominately derived by the extent they are able to alleviate binding of N and N-1 constraints on Line 94T.

Figure 3-1 demonstrates that both Option 2 and 2A fully alleviate the binding of the Molong to Orange N constraints compared to the constraint binding in the Base Case, while for the N-1 constraints in Figure 3-2 there is only a minor discrepancy between the binding percentages of Option 2 and 2A in the years 2040-41 to 2041-42. This means that the additional thermal rating for Option 2 (177 MVA summer-day) offered no material incremental relief over Option 2A (152 MVA summer-day). Any rating above the rating

[6] At least 150 MVA rating was specified as a rating requirement in the PADR.

required to fully alleviate the binding of the Molong to Orange constraints will provide no material additional market benefit.

Figure 3-1: Forecast Line 94T N-0 constraint binding percentage for Step Change scenario[7]

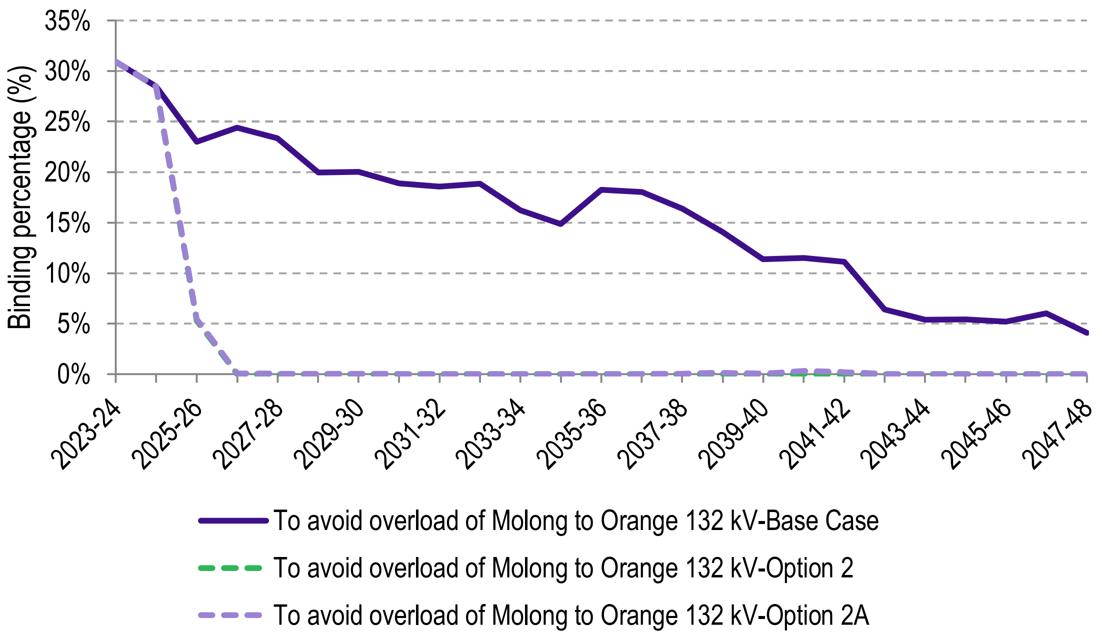
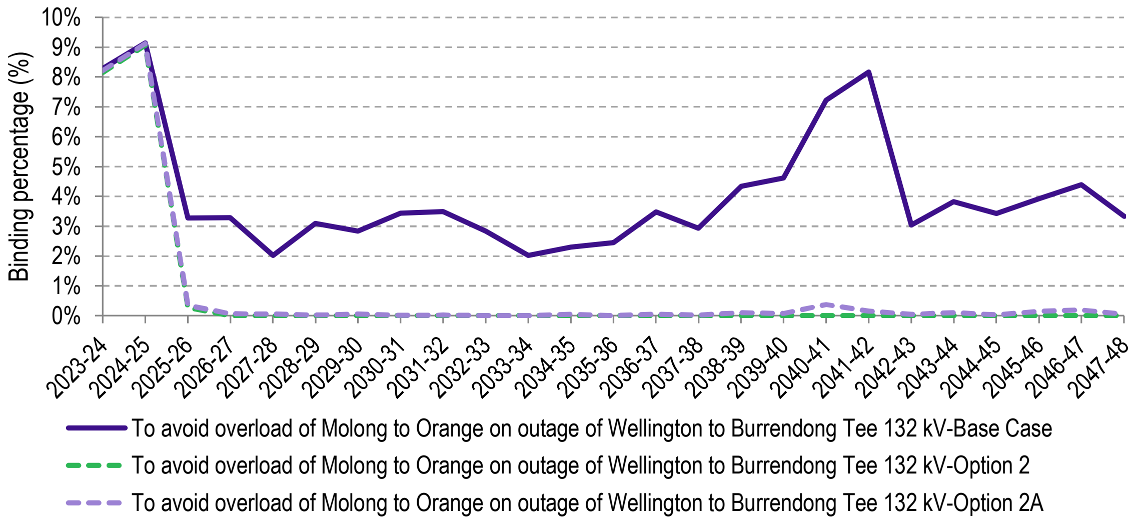


Figure 3-2: Forecast Line 94T N-1 constraint binding percentage for Step Change scenario

[7] Option 2 and 2A completely alleviate the constraint binding and for this reason light purple and green dashed lines are the same and overlap for all periods.



These outcomes are reflected in the forecast gross market benefits for Option 2 and 2A under all scenarios (provided in the Table 3-2 below).

Table 3-2: Summary of forecast gross market benefits of options 2 and 2A for core simulation relative to each scenario's Base Case, millions real June 2021 dollars discounted to June 2021

Option	Description	Timing	Forecast gross market benefits ($m) core simulations		
			Step Change	Progressive Change	Hydrogen Superpower
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	18.1	50.6
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	18.2	50.6

Overall, analysis of the PADR forecast outcomes and additional test simulations indicate that gross market benefits increase when thermal line ratings increase to at least 152 MVA (summer-day), but further improvement of the thermal line rating does not lead to further benefits, as the constraint is already fully alleviated. We therefore consider that the gross market benefits of Option 2 will not be materially reduced even when the thermal rating of the line is reduced to at least 152 MVA.

4. Credible options assessed

We considered credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective. This includes the six options originally proposed in the PADR.

Table 4-1 summarises each of the credible options we considered to address the identified need.

Table 4-1: Summary of the credible options

Option	Description	Estimated capex (June $2022 million)	Expected commissioning year
1	Increase transmission line design temperature of Line 94T	1.41	2024/25
2	Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures	7.50	2025/26
2A	Restring Line 94T with higher rated 'Partridge/ACSS/HS285' conductor on existing structures	8.16	2025/26
2B	Implementing Option 2 together with power flow controllers	25.97	2025/26
3	Replacing Line 94T with a double circuit transmission line	38.54	2026/27
4	Installation of a 50MW/300MWh BESS at Molong substation	185.69	2025/26

* All estimated capex (+/- 25%)

The remainder of this section provides further detail on each of these credible options.

4.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken will compare the costs and benefits of each option to a base case. The base case is the projected case where no action is taken to address the identified need as per section 3.3 of the RIT-T Application Guidelines, which is extracted below[8].

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

[8] As per the RIT-T Application Guidelines, the base case provides a clear reference point for comparing the performance of different credible options. Australian Energy Regulator. "*Application guidelines Regulatory Investment Test for Transmission - August 2020*." Melbourne: Australian Energy Regulator, 2020.21. Accessed 12 March 2022. https://w ww.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20trans mission%20application%20guidelines%20-%2025%20August%202020.pdf

Under the base case, no investments are made to meet the identified need to improve capacity for renewable generation in the Molong and Parkes area. However, we have included the preferred option (Option 7D) from the BOP RIT-T in the base case. Details regarding this option, as well as the explanation for its inclusion are provided in section 2.2.3 of the PADR.

This will result in curtailment of renewable generation to avoid thermal overloading of Line 94T. The forecasted curtailment on the NEM will increase from approximately 130,000 MWh per annum in 2022 to 142,000 MWh per annum by 2030. As a result of the curtailment, reliance on existing higher cost generation and investment in new generation in other parts of the NEM will be required to meet expected load forecasts.

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.

4.2. Option 1 – Increase transmission line design temperature of Line 94T

Option 1 involves increasing Line 94T's summer daytime thermal rating from 112 MVA to 125 MVA by increasing the maximum design temperature of the existing Wolf conductor from 85C to 100C and Neon conductor from 85C to 92C.

This is achieved by:

- replacing one structure; and
- converting insulator arrangements of 18 structures.

While this option will increase the thermal rating of Line 94T, it will not completely relieve renewable generation curtailment in the Molong and Parkes area.

The estimated capital cost of this option is approximately $1.41m (June $2022) +/-25 per cent. Table 4-2 shows the expected expenditure profile of this option. This option is expected to take 21 months to deliver, with commissioning possible in 2024/25. This option is expected to have an asset life of 40 years.

Table 4-2 Option 1 Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	0.24
FY25	1.16
Total capital cost	**1.41 (+/- 25%)**

4.3. Option 2 – Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures

Option 2 involves increasing Line 94T's summer daytime thermal rating from 112 MVA to at least 150 MVA by restringing Line 94T with a higher capacity conductor (i.e., Flicker conductor).

This is achieved by:

- replacing the existing conductor between structures 1 and 95 with a new Flicker ACSS conductor (approximate circuit length of 27.04 kilometres);
- replacing the existing conductor between structure 96 and the gantry of Molong substation with a new Linnet ACSS conductor (approximately circuit length of 1.85 kilometres);
- replacing 11 structures (the replacement of 9 of these structures may be reduced to cantilever arm replacement upon further assessment); and
- converting three suspension structures to tension structures.

The final configuration of Line 94T would be as follows:

Table 4-3 Configuration of Line 94T with Option 2

Structure Range	Three Phase Single Circuit Length (km)	Conductor	Maximum Operating Temperature (C)	Thermal Rating (MVA)
From Orange North Gantry to Str. 1 Back Span	0.127	Existing Oxygen AAAC/1120	85	169
From Str. 1 Ahead Span to Str. 95 Back Span	27.04	New Flicker ACSS/TW/HS285	80	150
From Str. 95 Back Span to Molong Gantry	1.85	New Linnet ACSS	90	150

The estimated capital cost for the option is approximately $7.50 million (June $2022) +/-25 per cent. Table 4-4 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26. This option is expected to have an asset life of 40 years.

Table 4-4 Option 2 Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	0.45
FY25	4.75
FY26	2.30
Total capital cost	**7.50 (+/- 25%)**

4.4. Option 2A – Restring Line 94T with higher rated 'Partridge/ACSS/HS285' conductor on existing structures

Option 2A involves increasing Line 94T's summer daytime thermal rating from 112 MVA to at least 152 MVA by restringing Line 94T with a higher capacity conductor than Option 2 (i.e., a Partridge conductor).

This is achieved by:

- replacing the existing conductor between structure 1 and the gantry of Molong substation with a new Partridge ACSS conductor (approximate circuit length of 28.89 kilometres);

- replacing 11 structures (the replacement of 9 of these structures may be reduced to cantilever arm replacement upon further assessment); and
- converting three suspension structures to tension structures.

The final configuration of Line 94T would be as follows:

Table 4-5 Configuration of Line 94T with Option 2A

Structure Range	Three Phase Single Circuit Length (km)	Conductor	Maximum Operating Temperature (C)	Thermal Rating (MVA)
From Orange North Gantry to Str. 1 Back Span	0.127	Existing Oxygen AAAC/1120	85	169
From Str. 1 Ahead Span to Molong Gantry	28.89	New Partridge ACSS/HS285	250	152

The estimated capital cost for the option is approximately $8.16 million (June $2022) +/-25 per cent. Table 4-6 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26. This option is expected to have an asset life of 40 years.

Table 4-6 Option 2A Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	0.50
FY25	5.17
FY26	2.49
Total capital cost	**8.16 (+/- 25%)**

4.5. Option 2B – Option 2 with Power Flow Controllers

Option 2B involves implementing Option 2 (i.e., increasing Line 94T summer daytime thermal rating from 112 MVA to at least 150 MVA by restringing Line 94T with a higher capacity conductor) as well as installing power flow controllers. Specifically, this option involves installing one unit of SmartValve SV10-1800 model at Molong substation, which can, in close to real time, increase or decrease the reactance of Line 94T. This has the effect of diverting power away or drawing more power towards a circuit on which this capability is available. Diverting power away from Line 94T during peak solar generation periods would help in avoiding circuit overloads.

This is achieved by:

- replacing the existing conductor between structures 1 and 95 with a new Flicker ACSS conductor (approximate circuit length of 27.04 kilometres);
- replacing the existing conductor between structure 96 and the gantry of Molong substation with a new Linnet ACSS conductor (approximately circuit length of 1.85 kilometres);

- replacing 11 structures (the replacement of 9 of these structures may be reduced to cantilever arm replacement upon further assessment);
- converting three suspension structures to tension structures; and
- installing one unit of SmartValve SV10-1800 model at Molong substation.

The final configuration of Line 94T would be similar to Option 2, as set out in Table 4-3.

The estimated capital cost for the option is approximately $25.97 million (June $2022) +/-25 per cent. Table 4-7 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26. This option is expected to have an asset life of 25 years.

Table 4-7 Option 2B Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	1.58
FY25	16.45
FY26	7.94
Total capital cost	**25.97 (+/- 25%)**

4.6. Option 3 – Double circuit transmission line

Option 3 involves removing the existing structures and conductors of Line 94T and replacing them with new dual circuit towers and dual conductors with higher ratings.

This is achieved by:

- removal of the 106 pole structures along the entire length of Line 94T;
- construction of 59 double circuit suspension structures;
- converting three suspension structures to tension structures; and
- stringing of dual circuit towers with higher rated conductors (principally Flicker conductors)

The estimated capital cost for the option is approximately $38.54 million (June $2022) +/-25 per cent. Table 4-8 shows the expected expenditure profile of this option. This option is expected to take 30 months to deliver, with commissioning possible in 2026/27. This option is expected to have an asset life of 40 years.

Table 4-8 Option 3 Capital Cost (June $2022 million)

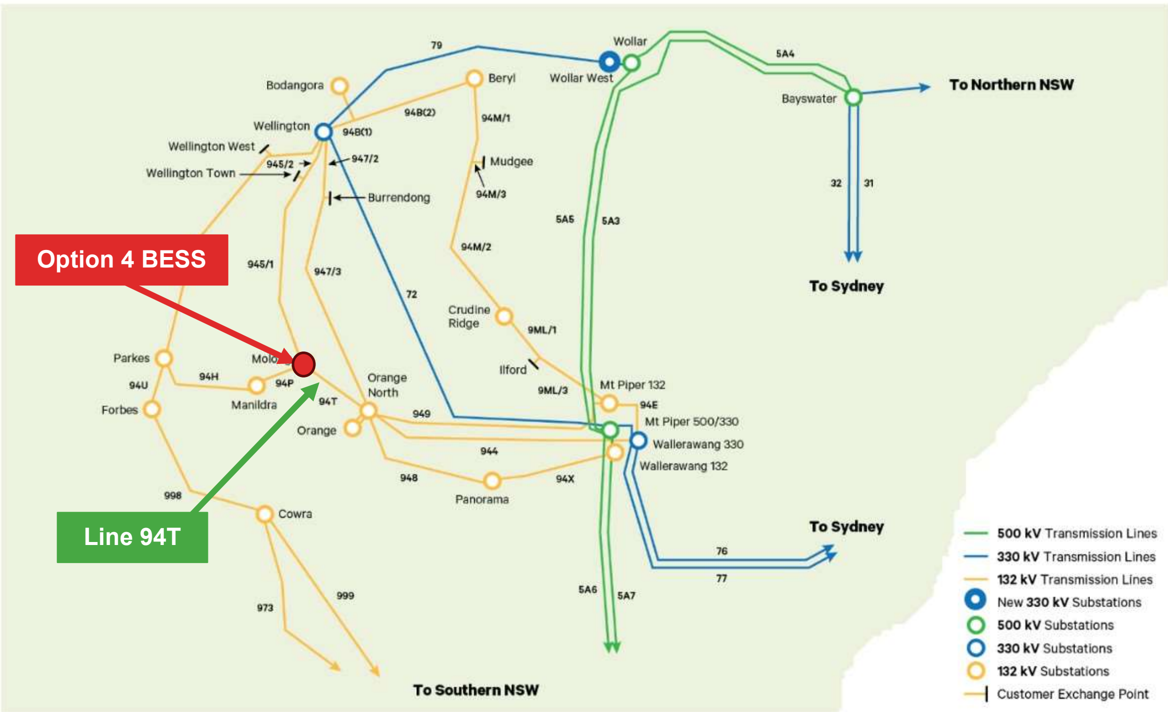
Item	Capital expenditure (June $2022 million)
FY24	1.98
FY25	23.98
FY26	12.58
Total capital cost	**38.54 (+/- 25%)**

4.7. Option 4 – Install a 50MW/300MWh BESS

Option 4 involves installing a 50MW/300MWh BESS at Molong substation. Based on our load flow studies, we have determined that a 50MW battery with 6 hour duration (i.e. BESS to charge at the time when solar generation is highest) is required to address the constraint on Line 94T. This is achieved by:

- Installation of a 50MW/300 MWh BESS at Molong substation;
- Construction of a new 132kV switchbay; and
- Laying of approximately 110m underground 132kV cable.

Figure 4-1 Location of BESS under Option 4



The estimated capital cost for the option is approximately $185.69 million (June $2022) +/-25 per cent. Table 4-9 shows the expected expenditure profile of this option. We have estimated possible commissioning of this Option in 205/26, however detailed timing and cost analysis of this option has not been undertaken at this stage of the RIT-T process, as the costs are significantly higher than for other options. However, we do not anticipate that the relative timing of this option is material to the outcome. This option is expected to have an asset life of 25 years.

Table 4-9 Option 4 Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	18.76
FY25	98.47
FY26	68.46
Total capital cost	**185.69 (+/- 25%)**

4.8. Options considered but not progressed

We have also considered whether other options could meet the identified need. These options have not changed since the publication of the PADR. The reasons these options were not progressed are summarised in Table 4-10.

Table 4-10: Options considered but not progressed

Option	Reason(s) for not progressing
Increase Line 94T conductor rating to 138MVA for contingency events only	This option increases the contingency rating for Line 94T to 138 MVA. How ever, it does not increase the continuous rating of Line 94T. Network modelling shows thermal overloading of Line 94T is expected under normal system conditions. Hence, achieving a higher rating for contingency situations only, which enables overloading for approximately 30 minutes, will not address the identified need and therefore is not technically feasible.
Rebuild Line 94T as a higher rated single circuit transmission line	This option involves removing the existing structures and conductors of Line 94T and replacing it with new single circuit towers and conductors with higher ratings. This option would be considerably more expensive than the other network options and is not expected to deliver significantly higher benefits. This option will also need significant outage of existing Line 94T which will lead to more generation curtailment during the construction period. Therefore, this option is considered not commercially feasible under the RIT-T.
New transmission line parallel to existing Line 94T	This option involves building a new single circuit transmission line parallel to the existing Line 94T and may require widening of the existing Line 94T easement. This option would be considerably more expensive than the other network options and is not expected to deliver significantly higher benefits. Therefore, this option is considered not commercially feasible under the RIT-T.
Implement Stage 2 of the Maintaining Reliable Supply to Bathurst, Orange and Parkes area project	This option would bring forward the timing for Stage 2 of this project. The preferred option for Stage 2 in the Maintaining Reliable Supply to Bathurst, Orange, and Parkes area RIT-T PACR is establishing a Wellington to Parkes 132 kV transmission line. Establishing this transmission line will not address the identified need in this RIT-T as it will not relieve the constraints on Line 94T and is therefore considered not technically feasible under this RIT-T. Alternate Stage 2 options, such as establishing a 330/132 kV supply point at Orange will cost substantially more than other network options considered. The timing of Stage 2 is also uncertain, and it will take significantly longer to implement. Therefore, this option is considered not commercially feasible under this RIT-T.

4.9. No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact[9]. A 'material inter-network impact' is defined in the NER as:

> *"A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another*

[9] As per clause 5.16.4(b)(6)(ii) of the NER.

Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following[10]:

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We consider that each credible option satisfies these conditions. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with any of the credible options considered.

[10] Inter-Regional Planning Committee. "*Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations*." Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

5. Ensuring the robustness of the analysis

This section outlines the approach that we have undertaken to assess the net benefits associated with each of the credible options against the base case.

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 two other means. First, we have undertaken sensitivity analysis to determine how the net benefits change in relation to changes in key input assumptions. Second, we have identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three 'reasonable scenarios'

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

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[31] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[11]

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

AEMO's latest ISP (2022) includes four scenarios – the Slow Change scenario, Step Change scenario, Progressive Change scenario, and Hydrogen Superpower scenario.[12] AEMO has identified that the Slow Change scenario has a very low probability of occurring (approximately 4%). We have excluded this scenario as it does not have a reasonable likelihood of arising. For the purposes of this RIT-T, we have modelled outcomes under the remaining three scenarios from AEMO's latest ISP, i.e., the Step Change scenario, Progressive Change scenario, and the Hydrogen Superpower scenario.

[11] AER, *Regulatory investment test for transmission*, August 2020, clause 20(b).
[12] AEMO, 2022 Integrated System Plan, June 2022, p.30-31.

The scenarios also vary by local spot load forecast, 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 (see Section 2.2.2 of the PADR)

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

Table 5-1 Summary of the scenarios

Variable	Step Change	Progressive change	Hydrogen Superpower
Capital costs	Base estimate	Base estimate	Base estimate
Demand	Central demand forecast (ISP POE10 and Orange North POE50)	Central demand forecast (ISP POE10 and Orange North POE50)	High demand forecast (ISP POE10 and Orange North POE10)
New renewable generation in the area	All in-service, committed and anticipated generators (as outlined in section 2.2)	All in-service, committed and anticipated generators (as outlined in section 2.2)	All in-service, committed and anticipated generators (as outlined in section 2.2)
Wholesale market benefits estimated	EY estimate based on the 'step change' 2022 ISP scenario	EY estimate based on the 'progressive change' 2022 ISP scenario	EY estimate based on the 'hydrogen superpower' 2022 ISP scenario
Discount rate	5.50%	5.50%	5.50%

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.:

- 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.

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

5.3. Sensitivity and threshold analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

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

- higher and lower capital cost assumptions for the credible options;
- alternate commercial discount rate assumptions;
- excluding stage 1 of the preferred option from the BOP RIT-T

- including stage 2 of the preferred option from the BOP RIT-T
- higher load forecasts for the Orange area; and
- higher forecast for renewable generation capacity in the Molong and Parkes area

The results of the sensitivity tests are discussed in section 7.5. The sensitivity testing also includes 'boundary testing', where relevant, to investigate what key variables would need to change by to change the identified preferred option.

6. Estimating the market benefits

6.1. Assessment against the 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, i.e.,[13]

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

Under the base case, thermal limitations on Line 94T will continue to constrain the amount of renewable generation that can be supplied from the Molong and Parkes area to load in the Orange area. Expected increases in renewable generation capacity in the Molong and Parkes area, and expected growth in demand in the Orange area, will result in the network constraint binding more often and to a greater extent, which in turn will increase the volume of renewable generation curtailed. As a result of these constraints binding, residual load in the Orange area must be supplied from other parts of the NEM. This would increase reliance on existing conventional generation connected to other parts of our network, which would impose higher fuel costs on customers, and increase the need for additional generation capacity to be installed to meet demand growth in the Orange area.

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.

6.2. Options uprating Line 94T would avoid future replacement costs

Under the base case, we expect to remediate low clearance conductors, which pose a public safety risk on Line 94T in the next five to ten years at an estimated cost of $1.25m ($Real21). Options 2, 2A, 2B and 3 are expected to avoid this future remediation cost (and so provide an economic benefit). While we recognise this will lead to a cost saving under the proposed options, given the relatively small value of remediating low clearance conductors when discounted back over a five to ten year period, and the fact that this will apply to all options equally;(meaning the relative rankings of the options will not be altered), we have decided not to include this cost as part of the cost benefit analysis.

6.3. Wholesale market benefits

As outlined in section 4, the options considered in this PACR involve either increasing the capacity of Line 94T or installing and operating a BESS to dispatch to the wholesale market. These options can offset more costly generation that would otherwise operate in the NEM, and therefore provide wholesale market benefits. These benefits are outlined in Table 6-1.

[13] AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, p. 21.

Table 6-1 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 parties, other than the RIT–T proponent, due to differences in the timing of new plant, capital costs, and operating and maintenance costs	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. Removing thermal constraints on Line 94T will allow additional solar generation to be built. Solar generation has lower capital expenditure compared to thermal and wind generators, lowering the capital expenditure required to service the NEM.
Changes in fuel consumption arising through different patterns of generation dispatch	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. Removing thermal constraints on Line 94T will allow additional solar generation to enter the NEM, replacing more expensive thermal and wind generation. This will bring down the overall cost of generation in the NEM.
Changes in the timing of unrelated expenditure	This category of market benefit is expected where credible options may delay the need for additional expenditure, such as planned transmission investment.
Changes in voluntary load curtailment	This category of market benefit is expected where credible options allow for additional generation to be dispatched due to the relieving of existing Line 94T constraints. Removing thermal constraints on Line 94T will allow additional solar generation to enter the NEM that may have otherwise been curtailed.
Changes in involuntary load shedding	As the identified need for this RIT-T is to increase overall net market benefits in the NEM by relieving existing Line 94T constraints on renewable generation in the Molong and Parkes area, it will have an immaterial impact on load, however small instances of load shedding may be avoided.

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. As outlined in section 5.1, these benefits have been modelled under the 'step change' scenario, 'progressive change' scenario, and 'hydrogen superpower' scenario identified by AEMO in the 2022 ISP. An overview of the modelling conducted by EY is presented in Appendix C.

As outlined in Section 2.2, AEMO has recently published its 2023 IASR assumptions and its 2023 ESOO demand forecasts that will feed into its 2024 draft ISP. We have not updated the market benefit modelling to include the 2023 IASR assumptions and 2023 ESOO demand forecasts given we do not expect the updated assumptions to change the relative ranking of the options. We have also considered the relative size of the project and the considerable time and cost that would be required to re-run the modelled scenarios under the updated assumptions.

As outlined in Section 3.4, we also note the apparent discrepancy between thermal rating attributed to Options 2 and 2A (177 MVA and 152 MVA respectively for summer day) in the market modelling and the effective thermal rating of the lines as reported in the PADR (reported as "at least 150 MVA" and "at least 152

MWA" respectively for Options 2 and 2A). Considering that the forecast gross market benefits of these two options were similar, this phrasing was to emphasise that additional line rating beyond 150 MVA is not forecast to be heavily utilised and does not contribute to additional alleviation of the Line 94T constraint binding. The actual rating applied to Option 2 of 177 MVA was consistent with the thermal capability of the conductor.

6.4. General modelling parameters adopted

The RIT-T analysis spans a 25-year assessment period from 2022/23 to 2047/28.

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

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this 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 3.21%,[14] and an upper bound discount rate of 7.50 per cent (i.e., the lower and upper bounds in the 2021 IASR[15]).

6.5. Classes of market benefit not considered material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(4) requires Transgrid to consider the following classes of market benefits, arising from each credible option. We consider that none of the classes of market benefits listed in Table 6-2 are material for this RIT-T assessment for the reasons provided.

Table 6-2 Reasons non-wholesale electricity market benefits are considered immaterial

Market benefits	Reason
Changes in network losses	There is not expected to be any material difference in transmission losses between options.
Changes in ancillary service costs	While the cost of Frequency Control Ancillary Services (FCAS) may change because of changed generation dispatch patterns and changed generation development following any increase to transfer capacity, we consider that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option. There is no expected change to the costs of Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) as a

[14] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Transgrid 2023-28 – Final Decision – PTRM – April 2023.xlsx*), 'WACC' sheet, cell R23.
[15] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 105.

	result of the options being considered. These costs are therefore not considered material to the outcome of the RIT-T assessment.
Competition benefit	Competition benefits under the RIT-T relate to net changes in market benefits, arising from the impact of the credible option on the bidding behaviour of market participants in the wholesale market. While each of the credible options considered is designed to address network constraint, we consider that competition benefits are unlikely to be material and do not intend to estimate them as part of this RIT-T. This is due to all options being expected to have a similar effect on the wholesale market through relieving the existing constraint of Line 94T in Central NSW. In addition, the calculation of competition benefits requires substantial additional market modelling. We consider that this modelling exercise would be disproportionate to any competition benefits that may be identified for this specific RIT-T assessment, particularly the difference between options in terms of competition benefits
Option value	Option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change. We note that no credible option identified is sufficiently flexible to respond to change or uncertainty. Additionally, a significant modelling assessment would be required to estimate the option value benefit, but it would be disproportionate to potential additional benefits for this RIT-T. Therefore, we have not estimated any additional option value benefit.

6.6. Approach to estimating option costs

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

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).[16]

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in real, 2021/22 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

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

[16] For further detail on our cost estimating approach refer to section 7 of our Augmentation Expenditure Overview Paper submitted with our 2023-28 Revenue Proposal.

Transgrid

7. Net present value results

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of the options to the base case. The benefits of each credible option are represented by reduction in costs or risks compared to the base case.

The accompanying market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option modelled.

7.1. Step Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Step Change' scenario from the 2022 ISP. It also assumes the Orange North demand forecasts and all in-service, committed and anticipated renewable generators in the Molong and Parkes area (as outlined in section 2.2). Under this scenario, both Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $19 million in June $2022).

In comparison to Option 1, Options 2 and 2A are expected to provide higher gross benefits. Both options alleviate thermal constraints on Line 94T, allowing for an increase in the supply of solar generation in the Molong and Parkes area to the Orange area. This avoids the need to build and operate more expensive generators, such as wind or thermal generators, generating savings in capital costs and fixed operating costs. Option 1' s lower thermal rating alleviates less thermal constraint on Line 94T compared to the top ranked options, producing lower gross benefits. The higher gross benefits of the top ranked options offset the relatively higher cost of these options compared to Option 1.

While Options 2B and 3 are expected to provide similar gross benefits to Options 2 and 2A, they are both more expensive to implement. Likewise, Option 4 is expected to yield the greatest gross benefits of all the options considered but will also involve significantly higher cost than any of the other options. Our analysis indicates that the higher costs of implementing Options 2B, 3 and 4 outweigh the market benefits that each option is expected to deliver and therefore impose net costs on the market.

7.1.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The principal driver of market benefits is the extent to which each of the options allows for reduced network congestion and consequently less renewable energy spill. The gross benefits associated with Options 2, 2A, 2B and 3 are fairly similar, albeit higher for Options 2 and 2A. The reason for lower benefits of Option 2B and Option 3 relates to their impact on the power flow of the network due to different Line 94T parameters in these options.

For Option 2B, it is forecast that with the power flow controller in place, power flow in the direction towards Molong reduces and is diverted to other nearby lines causing congestion in other parts of the nearby network. This is forecast to result in additional renewable spill, resulting in lower gross benefits than Option 2.

Option 3 is forecast to result in a lower equivalent impedance in the Molong to Orange transmission lines, and in transmission corridors through this flow path towards the Sydney West. As a result, the flow on the lines in this direction is forecast to increase relative to other options (although a significantly higher flow is still forecast on the higher voltage network). One major impact of the lower impedance of the flow path is that the modelling forecasts more frequent binding of the constraint on the Wellington to Wellington Town line. As a result, forecast energy spill under Option 3 is higher.

Option 4 produces the highest gross benefit compared to the other Options. The use of a BESS allows for renewable generation to be stored and exported to the grid at times when it will provide the greatest benefit (which may differ from the times when renewable generators are producing).

Table 7-1: NPV of gross economic benefits relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	18.72
Option 2	25.44
Option 2A	25.31
Option 2B	23.14
Option 3	22.07
Option 4	107.77

7.1.2. Estimated costs

The table below summarises the present value of capital costs, and operating and maintenance costs, of each credible option relative to the base case. Options 1, 2 and 2A can be delivered at a lower cost than the other Options. Given the similarity in build specifications, the expected cost of implementing Option 2 and 2A are not expected to be materially different. In contrast, the expected cost of implementing Options 2B, 3 and 4 are considerably higher than the other options, i.e., in comparison to Option 2, Option 2B is more than three times the cost, Option 3 is more than five times the cost, while Option 4 is more than 24 times the cost).

Table 7-2: NPV of costs relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	1.44
Option 2	7.46
Option 2A	8.11
Option 2B	25.82
Option 3	38.26
Option 4	184.46

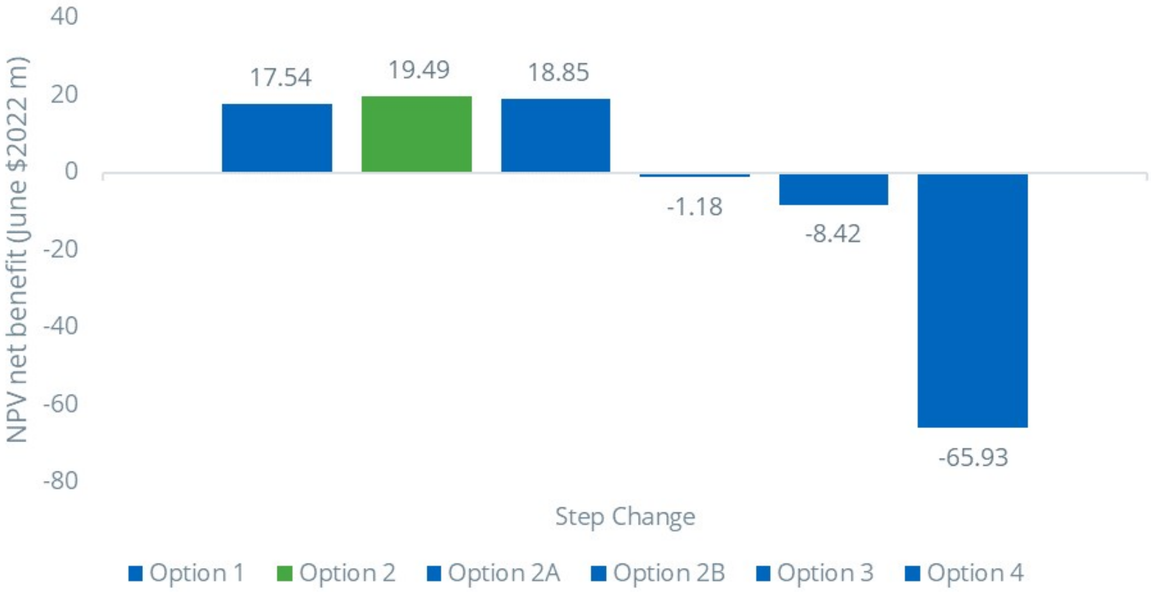
7.1.3. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-3: NPV of net economic benefits relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	17.54
Option 2	19.49
Option 2A	18.85
Option 2B	-1.18
Option 3	-8.42
Option 4	-65.93

Figure 7-1 NPV of net economic benefits relative to the base case – Step Change scenario (June $2022 million)



7.2. Progressive Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Progressive Change' scenario from the 2022 ISP. It also assumes the Orange North demand forecasts and all in-service, committed and anticipated renewable generators (as outlined in section 2.2).

The outcomes under this scenario are broadly similar to the Step Change scenario. In particular, Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $15 million in $June 2022). Option 1 is also expected to produce a net benefit under this scenario, while Options 2B, 3 and 4 all expected to generate net costs. In comparison to the Step Change scenario, all options with positive net market benefits are expected to generate relatively lower net benefits. However, the relative ranking of the options does not change.

The lower net benefits under this scenario are driven by lower gross benefits. Under the Progressive Change scenario, demand growth is assumed to be lower and carbon budgets are assumed to be less restrictive than the Step Change scenario. This result in a lower rate of congestion on Line 94T in the base case, meaning that the benefits associated with relieving congestion are also commensurately lower. Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.2.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. As with the Step Change scenario, the gross benefits associated with Options 2, 2A, 2B and 3 are fairly similar, albeit higher for Options 2 and 2A, while Option 4 produces the highest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit.

Table 7-4: NPV of gross economic benefits relative to the base case – Progressive Change scenario (June $2022 million)

Option	Progressive Change scenario
Option 1	14.55
Option 2	21.42
Option 2A	21.45
Option 2B	20.35
Option 3	16.94
Option 4	114.19

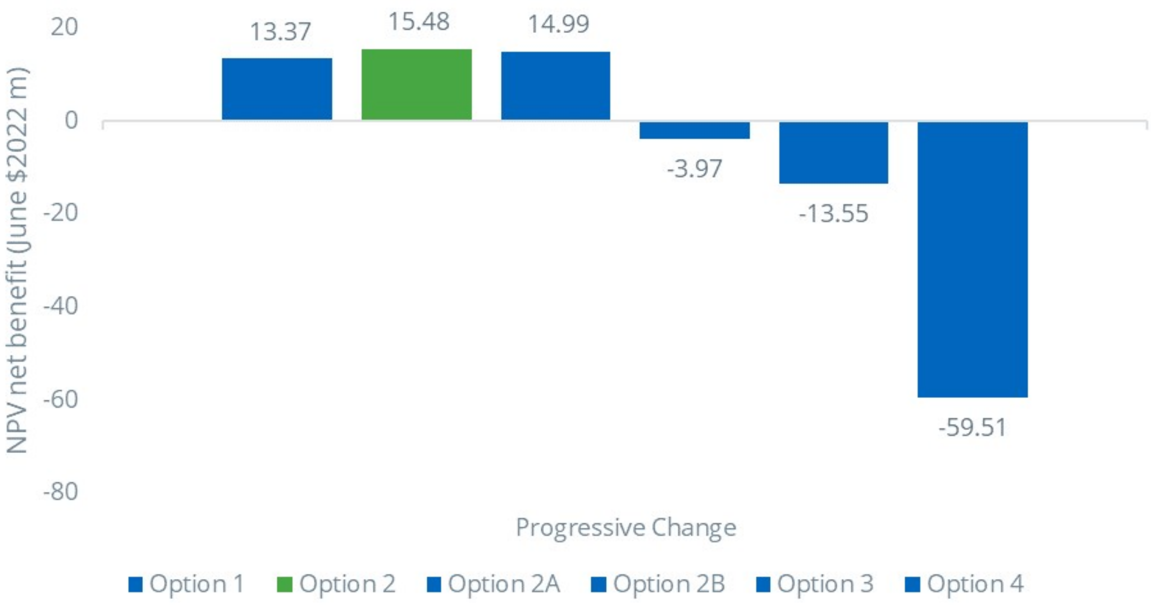
7.2.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. Similar to the Step Change scenario, the results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-5: NPV of net economic benefits relative to the base case – Progressive Change scenario (June $2022 million)

Option	Progressive Change scenario
Option 1	13.37
Option 2	15.48
Option 2A	14.99
Option 2B	-3.97
Option 3	-13.55
Option 4	-59.51

Figure 7-2 NPV of net economic benefits relative to the base case – Progressive Change scenario (June $2022 million)



7.3. Hydrogen Superpower scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Hydrogen Superpower' scenario from the 2022 ISP. It also assumes the high Orange North demand forecasts and all in-service, committed and anticipated renewable generators (as outlined in section 2.2).

The outcomes under this scenario are broadly similar to the other scenarios. In particular, Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $53 million in June $2022). Options 1 and 2B are also expected to produce net benefits under this scenario, while Options 3 and 4 are expected to generate net costs. In comparison to the Step Change scenario, all options generate higher net benefits except for Option 3. The relative ranking of the options does not change.

The Hydrogen Superpower scenario is forecast to have the highest benefits among all scenarios, due to the assumptions of higher demand growth, combined with a more restrictive carbon budget. This results in more renewable energy and hydrogen turbine capacity being built in the base case. Similar to the other scenarios, solar capacity is forecast to be the main technology, which is avoided with all options. However, in this scenario, network options are forecast to defer some hydrogen turbine capacity. Overall, fuel cost savings are expected in this scenario.

Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.3.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. As with the Step Change scenario, the gross benefits associated with Options 2, 2A, and 2B are fairly similar, although Option 2B now has the highest gross benefits of the three options. The gross benefits associated with Option 3 are lower compared to the other two scenarios. Option 4 produces the largest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit.

Option 2B's marginally higher gross benefits is due to the power flow controllers reducing the level of congestion on the Wellington to Wellington Town line during evening peaks. For further details, refer to the market modelling report.

Gross market benefits for Option 3 are similar to the Step Change scenario, which is a marked contrast to outcomes for the other options. This is predominately driven by the additional congestion on the Wellington to Wellington Town line that the double circuit line between Molong and Orange creates under the Hydrogen Superpower scenario, limiting the amount of wind generation that can flow to key load centres during evening peaks and requiring additional hydrogen turbine capacity to be built. For further details, refer to the market modelling report.

Table 7-6: NPV of gross economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)

Option	Hydrogen Superpower scenario
Option 1	39.74
Option 2	59.76
Option 2A	59.77
Option 2B	62.17
Option 3	17.15
Option 4	126.34

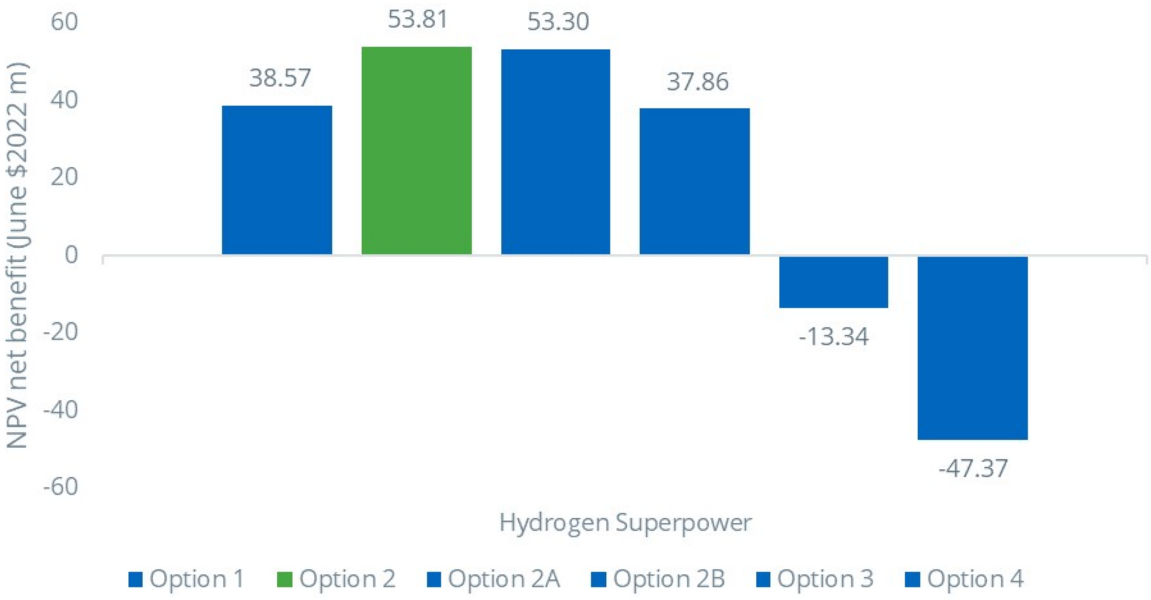
7.3.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-7: NPV of net economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)

Option	Hydrogen Superpower scenario
Option 1	38.57
Option 2	53.81
Option 2A	53.30
Option 2B	37.86
Option 3	-13.34
Option 4	-47.37

Figure 7-3 NPV of net economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)



7.4. Weighted net benefits

As outlined in section 5.2, we have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.4.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. Consistent with the results above, Option 4 is expected to produce the largest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit, followed by Options 2 and 2A which are expected to generate a very similar level of benefits.

Table 7-8: NPV of gross economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	21.25
Option 2	30.41
Option 2A	30.36
Option 2B	29.33
Option 3	19.64
Option 4	113.04

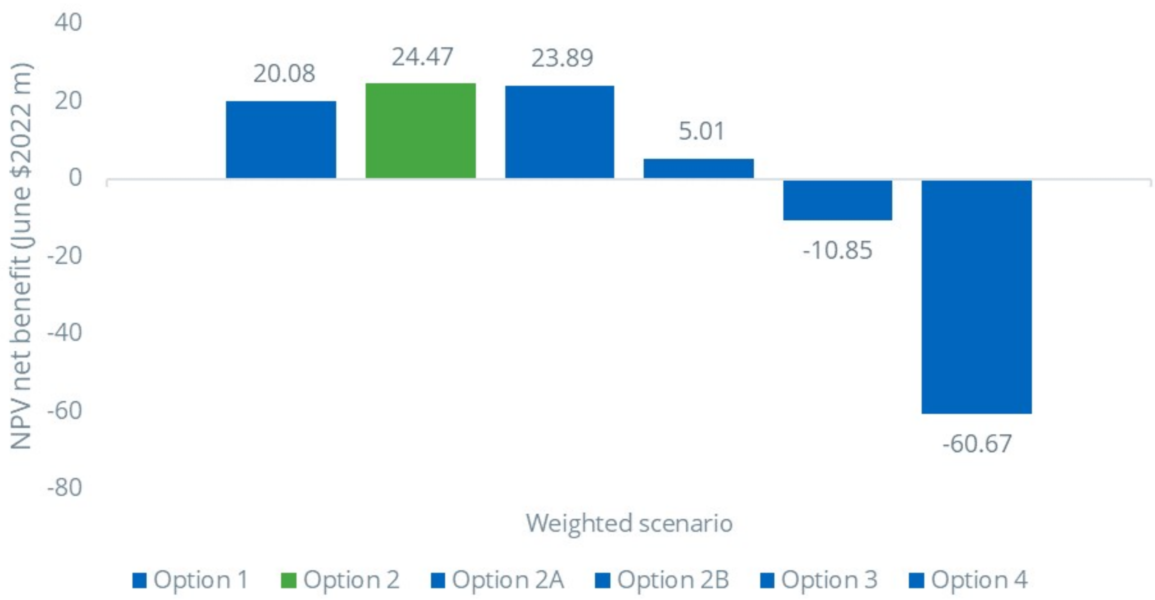
7.4.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results shows that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower. The net benefit of Option 2B is much lower, while Options 3 and 4 are expected to impose net costs on the market, due principally to the higher cost of implementing these options in comparison to Options 2 and 2A.

Table 7-9: NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	20.08
Option 2	24.47
Option 2A	23.89
Option 2B	5.01
Option 3	-10.85
Option 4	-60.67

Figure 7-4 NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)



7.5. Sensitivity testing

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

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

- higher and lower capital cost assumptions for the credible options (undertaken on the weighted scenario);

- alternate commercial discount rate assumptions (undertaken on the weighted scenario);
- excluding stage 1 of the preferred option from the BOP RIT-T (undertaken on all scenarios);
- including stage 2 of the preferred option from the BOP RIT-T (undertaken on the Step Change scenario);
- higher load forecasts in the Orange area (undertaken on the Step Change scenario); and
- higher forecast for renewable generation capacity in the Molong and Parkes area

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

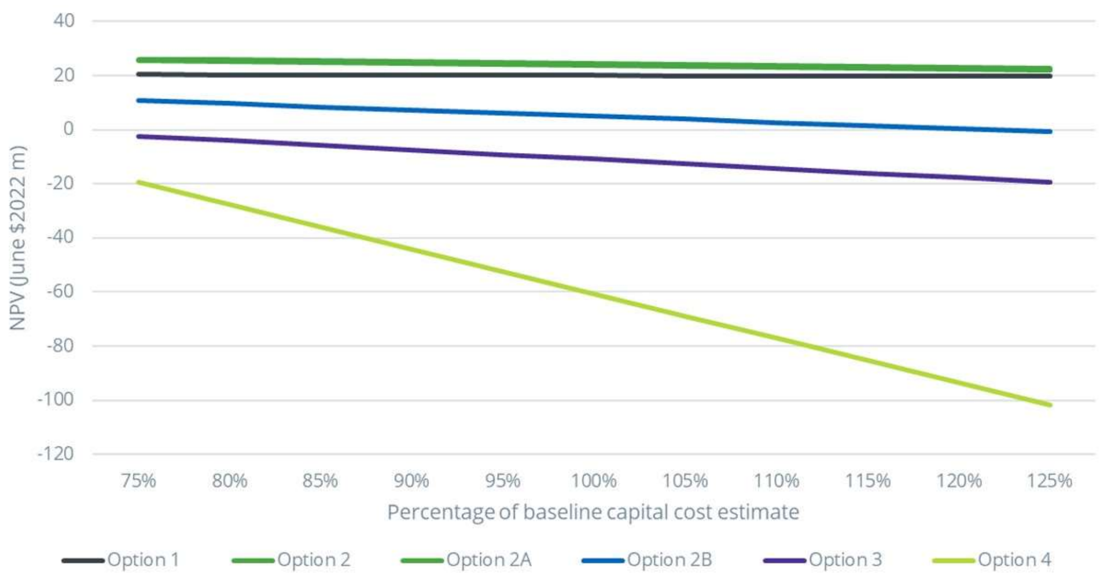
7.5.1. Sensitivity analysis on capital costs

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

Table 7-10: NPV of net economic benefits relative to the base case under lower and higher capital costs (June $2022 million)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Estimate - 25%*	*Estimate + 25%*	
Option 1	20.40	19.76	3
Option 2	26.13	22.80	1
Option 2A	25.70	22.08	2
Option 2B	10.77	-0.75	4
Option 3	-2.31	-19.38	5
Option 4	-19.53	-101.81	6

Figure 7-5 NPV of net economic benefits relative to the base case under lower and higher capital costs (June $2022 million)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we considered whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome.

Our findings show that if Option 2's costs were only 8.6% higher that our current forecasts then Option 2A would be the preferred option. This relatively small change in capital costs is one of the key reasons for progressing both Options 2 and 2A. We also conducted analysis on the required increase in Option 2's capital cost for Option 1 to produce a higher net benefit. Our findings show that Option 2's capital costs would need to increase by more than 66.0% in order for its net benefit to decrease below that of Option 1.

7.5.2. Sensitivity analysis on the discount rate

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 3.21%[17] and a high discount rate of 7.5% which aligns with the discount rate scenarios in the 2021 IASR. [18] Under both the low and high discount rate scenarios the relative rankings of the Options do not change.

Table 7-11: NPV of net economic benefits relative to the base case under lower and higher discount rates (June $2022 million)

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*3.21%*	*7.5%*	
Option 1	27.76	15.46	3
Option 2	36.14	17.59	1
Option 2A	35.67	16.98	2
Option 2B	15.17	-0.71	4
Option 3	-2.37	-15.27	5
Option 4	-32.49	-75.70	6

[17] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Transgrid 2023-28 – Final Decision – PTRM – April 2023.xlsx*), 'WACC' sheet, cell R23.

[18] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 105.

Figure 7-6 NPV of net economic benefits relative to the base case with lower and higher discount rates (June $2022 million)

We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result in Option 2 not being the preferred option. Our findings suggest that there are no positive discount rates that would result in Option 2A surpassing Option 2 as the preferred option. However, at a discount rate of 10.55% or higher Option 1 would become the preferred option.

7.5.3. Excluding stage 1 of the preferred option from the BOP RIT-T

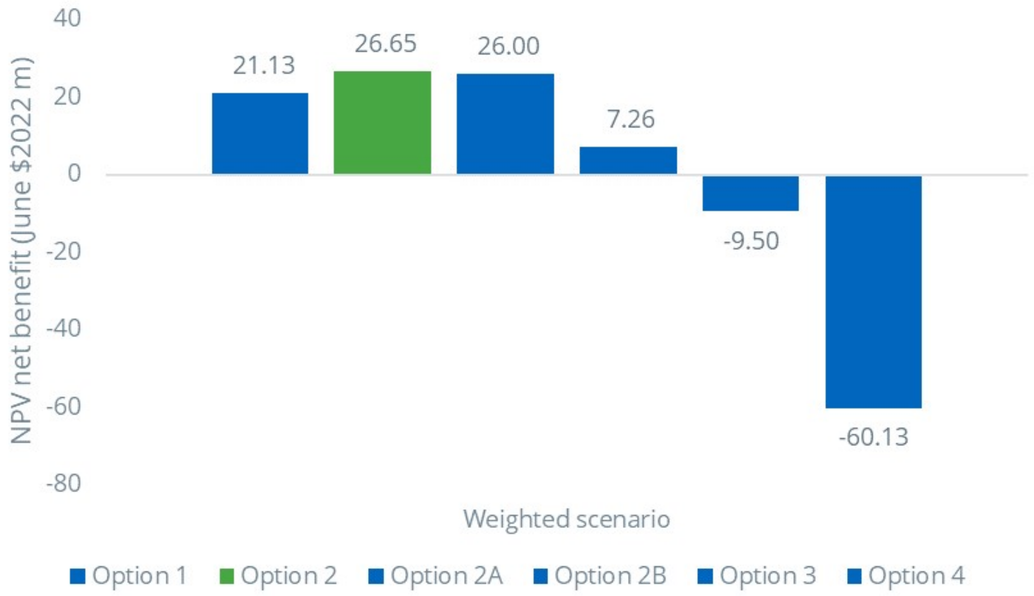
Our central analysis has included the preferred option for Stage 1 of the BOP RIT-T (i.e., Option 7D, which involves installation of a BESS and STATCOM at Parkes and Panorama). In this sensitivity, we have excluded the preferred option from the BOP RIT-T and modelled the credible options under each of the Step Change, Progressive Change and Hydrogen Superpower scenarios.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Option 2 and 2A remain the preferred options under all scenarios, with net economic benefits for all Options increasing compared to the central analysis. The removal of the BESSs at Panorama and Parkes increases the congestion on the network in the base case and allows the Line 94T options to alleviate more of the congestion, generating higher gross market benefits.

Table 7-12: NPV of net economic benefits relative to the base case after excluding the preferred BOP option (June $2022 million)

Option/scenario	Step Change	Progressive Change	Hydrogen Superpower	Weighted
Option 1	18.30	13.94	41.29	21.13
Option 2	21.20	16.78	58.85	26.65
Option 2A	20.55	16.30	57.94	26.00
Option 2B	0.50	-2.62	43.26	7.26
Option 3	-6.95	-12.74	-11.47	-9.50
Option 4	-65.41	-59.09	-46.61	-60.13

Figure 7-7 NPV of net economic benefits relative to the base case after excluding the preferred BOP option (Weighted scenario, June $2022 million)



7.5.4. Including stage 2 of the preferred option from the BOP RIT-T

Our central analysis has excluded the preferred option for Stage 2 of the BOP RIT-T, which involves building a 132kV line between Wellington and Parkes. This sensitivity assumes that Stage 2 of the BOP RIT-T is developed and commences operation from 2031-32.

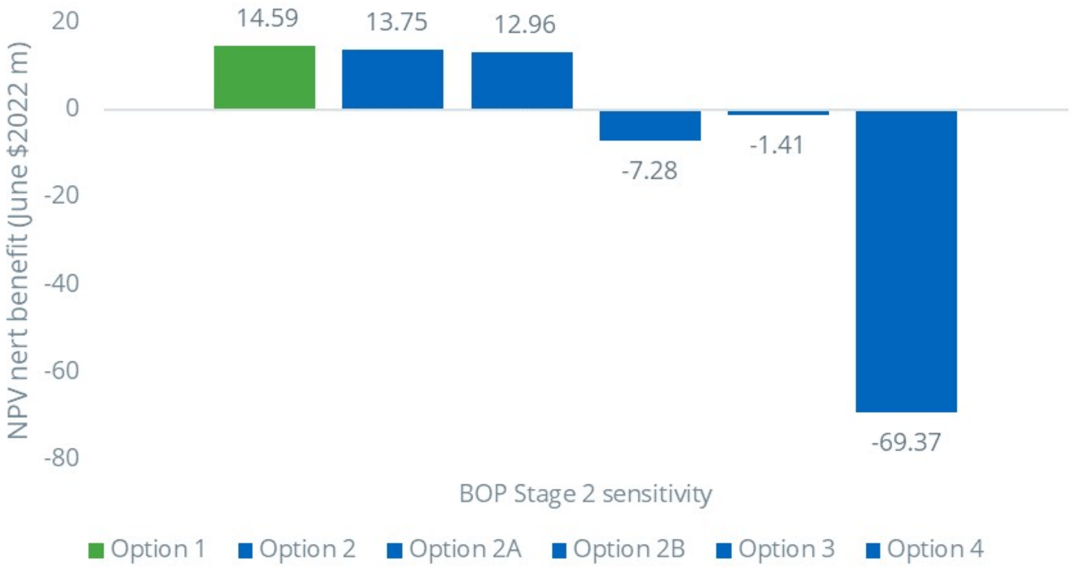
The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, Option 1 becomes the preferred option while Option 2 and 2A remain the next best alternatives. The construction of the Wellington to Parkes line will add additional transmission capacity to the region, and in turn lessen constraints on existing lines in the region such as Line 94T. This reduces the expected gross market benefits of all the Options considered in this RIT-T, and means that Option 1, which can be delivered at considerably lower cost, will provide the highest net benefit.

Unlike the other options, Option 3 has increased gross market benefits. This is due to Option 3 further benefiting from the reduced impedance of the Wellington to Parkes line, which avoids/reduces the congestion in the area compared to the central analysis.

Table 7-13: NPV of net economic benefits relative to the base case when including Stage 2 of the BOP RIT-T (June $2022 million)

Option	Step Change scenario
Option 1	14.59
Option 2	13.75
Option 2A	12.96
Option 2B	-7.28
Option 3	-1.41
Option 4	-69.37

Figure 7-8 NPV of net economic benefits relative to the base case when including Stage 2 of the BOP RIT-T (June $2022 million)



7.5.5. Higher load forecasts in the Orange area

We have considered a sensitivity that increases the forecast demand in the Orange area. Additional demand from this region would be expected to lead to further constraining of Line 94T under the base case scenario, meaning that credible options that reduce this constraint would create additional gross market benefits.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, the relative rankings of the Options are unchanged. In comparison to our central analysis, all the Options are expected to produce higher net economic benefits, except for Option 4 which experiences a minor decrease. Option 3 generates only a marginally higher gross market benefit but remains net negative, while all other Options generate higher positive net economic benefits.

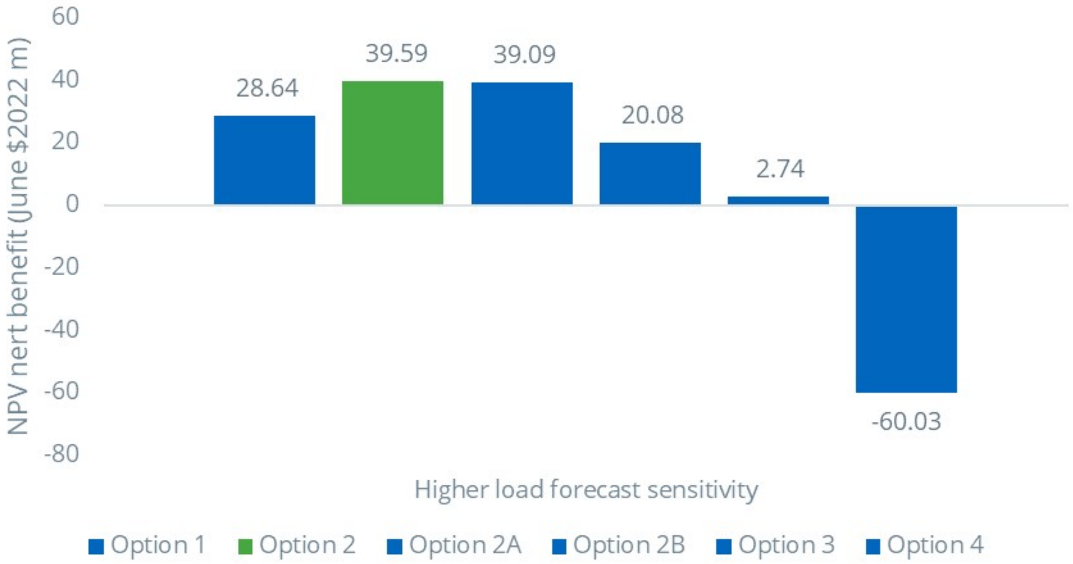
Option 1's relatively lower increase in gross market benefits, compared to the Option 2 variants, is due to lower thermal rating of Line 94T in this option, which limits the level of alleviated constraint bindings and gross benefits of the option.

Option 3 also delivers lower benefits compared to Option 2 variants for the same reason as the central analysis.

Table 7-14: NPV of net economic benefits relative to the base case with a larger demand forecast in the Orange area (June $2022 million)

Option	Step Change scenario
Option 1	28.64
Option 2	39.59
Option 2A	39.09
Option 2B	20.08
Option 3	2.74
Option 4	-60.03

Figure 7-9 NPV of net economic benefits relative to the base case with a larger demand forecast in the Orange area (June $2022 million)



7.5.6. Including three additional generators

We have considered a sensitivity that further increases renewable generation in the Molong and Parkes area. Under this sensitivity we include an additional three generators, of which two do not currently meet the requirements for an anticipated project, while Stubbo Solar Farm was just recently moved to the committed generator list. The additional generators are:

- 330 MW Wellington North Solar Farm, connected at Wellington 330 kV substation, to be commissioned on 1 January 2025.
- 400 MW Stubbo Solar Farm, connected at Uungula 330 kV substation on line 79, to be commissioned on 1 July 2024.
- 400 MW Uungula Wind Farm, connected at Uungula 330 kV substation on line 79, to be commissioned on 1 October 2025.

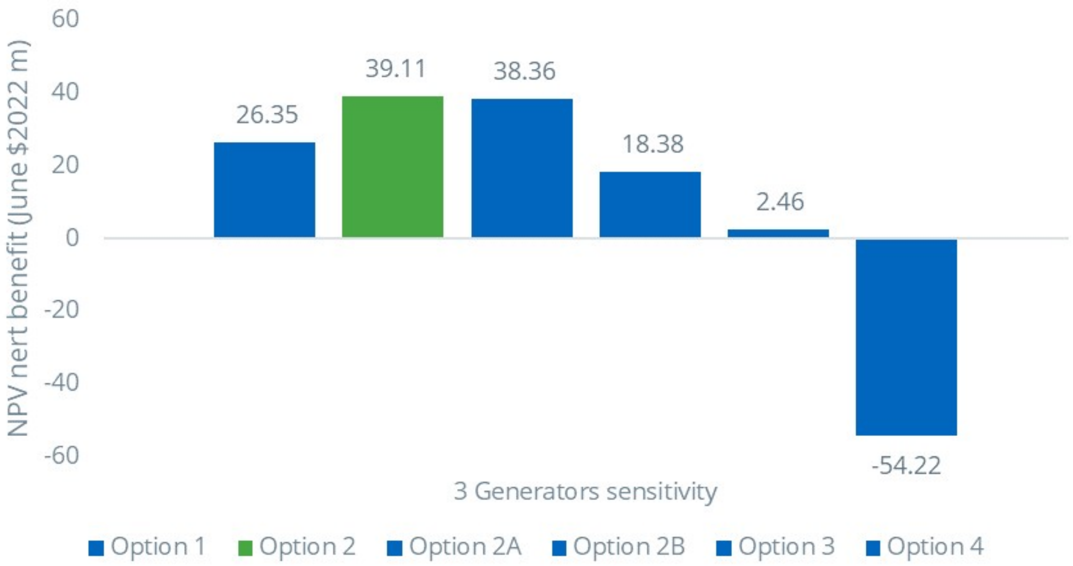
The addition of these three generators is likely to lead to further constraining of Line 94T under the base case as more renewable generation is available to be dispatched, meaning that credible options that reduce this constraint should create additional gross market benefits.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, the relative rankings of the Options are unchanged. In comparison to our central analysis, all of the Options are expected to produce higher net economic benefits. Option 3 and 4 generate only marginally higher gross market benefits but remain net negative, while all other Options generate higher positive net economic benefits.

Table 7-15: NPV of net economic benefits relative to the base case with additional renewable generation (June $2022 million)

Option	Step Change scenario
Option 1	26.35
Option 2	39.11
Option 2A	38.36
Option 2B	18.38
Option 3	2.46
Option 4	-54.22

Figure 7-10 NPV of net economic benefits relative to the base case with additional renewable generation (June $2022 million)



8. Conclusion

This PACR finds that Option 2 is the preferred option for meeting the identified need on a weighted basis and in the sensitivities assessed. This option involves increasing Line 94T's summer daytime thermal rating, by restringing Line 94T with a higher capacity conductor. The thermal rating of the new conductor would increase to at least 150 MVA under Option 2. Option 2 is expected to deliver approximately $24.5 million in net benefits over the assessment period (on a weighted-basis).

In the Project Assessment Draft Report (PADR) we identified Options 2 and 2A as the preferred options. We have decided to progress with Option 2 over Option 2A as Option 2 is expected to deliver approximately $24.5 million in net benefits over the assessment period (on a weighted-basis), which is higher than the $23.9 million in net benefits expected to be delivered by Option 2A.

Option 2 involves increasing Line 94T's summer daytime thermal rating from 112 MVA to at least 150 MVA, by restringing Line 94T with a higher capacity conductor (i.e., Flicker conductor).

This is achieved by:

- replacing the existing conductor between structures 1 and 95 with a new Flicker ACSS conductor (approximate circuit length of 27.04 kilometres);
- replacing the existing conductor between structure 96 and the gantry of Molong substation with a new Linnet ACSS conductor (approximately circuit length of 1.85 kilometres);
- replacing 11 structures (the replacement of 9 of these structures may be reduced to cantilever arm replacement upon further assessment); and
- converting three suspension structures to tension structures.

The estimated capital cost of restringing Line 94T with a higher capacity conductor under Option 2 is approximately $7.5 million.

We will now proceed to a detailed design stage for this option prior to its implementation. If, during the detailed design stage, another conductor with the same or higher rating and similar costs and benefits as Option 2, is found to be more fit for purpose, we may amend the preferred option to use the alternative conductor. We will only adopt an alternative conductor, if its use will not result in a material change to the net benefits of the option or a delay to when the option can be implemented and subject to updating stakeholders on the proposed changes.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4 of the National Electricity Rules version 203.

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.	See below
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	3 & Appendix B
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	See PADR
	(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 C
	(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;	7 & 8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	4 & 8

Appendix B Summary of consultation on the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process, besides those comments considered confidential. The points raised are grouped by topic and a response is provided to the points raised. All section references are to this PACR, unless otherwise stated.

Table 8-1 Summary of consultation on the PADR

Summary of comment(s)	Submitter(s)	Our response
Submission 1 - Solar farm operator		
The stakeholder supports the implementation of the preferred solutions and encourages the implementation of the solution as soon as possible. The solution should be commissioned no later than Q4 2025.	p.1-2	The timing of the preferred solution in this PACR is scheduled for 2025/26. This is in line with the stakeholder's suggested timing of no later than Q4 2025. We will consider further timing decisions as we undertake a more detailed design assessment of the preferred option following the conclusion of this PACR.
The stakeholder anticipates that the build-out of additional capacity in the region will exceed what has been assumed in the PADR (a further 1,500 MW of planned wind and solar in the Molong and Parkes area). This will likely lead to network constraints re-emerging and require further capacity increases in the future.	p.2	While it is possible that additional capacity will be added to the Molong and Parkes area, there is not yet sufficient certainty to include such potential projects in our market modelling. This is consistent with the approach set out in the RIT-T guidelines, which requires only committed and anticipated generation to be included. It is worth noting that in addition to the named committed and anticipated generation, the PADR market modelling undertaken for this RIT-T forecast that additional renewable capacity will be built in the Central West Orana Renewable Energy Zone (CWO REZ) across all modelled scenarios and options. Details of the additional unnamed forecast generation capacity in the PADR model were provided in Table 2-2 of the PADR. Therefore, we do not expect that an additional 1,500MW of renewable generation capacity in the

Summary of comment(s)	Submitter(s)	Our response
		Molong and Parkes area will change the preferred option. We have also undertaken a sensitivity scenario that includes an additional 3 generation projects as outlined in Section 7.5.6. Option 2 still remains the preferred option under this scenario.
The stakeholder noted that the effective ratings increase under Options 2 and 2A would be limited to at least 150 MVA and not 177 MVA and 152 MVA as indicated in the PADR. Transgrid should ensure that the market benefits remain the same under an at least 150 MVA scenario for both options.	p.2	The market modelling undertaken by EY was based on an assumed summer-day 177 MVA rating for Option 2 and 152 MVA for Option 2A. The modelled thermal rating of Option 2A is less than Option 2 in all time periods. However, forecast gross market benefits of these options are very similar. This is because the gross market benefits of Options 2 and 2A are predominately derived by the extent they are able to alleviate binding of N and N-1 constraints on Line 94T. Analysis of PADR outcomes showed that the rating above 152 MVA for Option 2 was not well-utilised because of additional constraints in the area. EY have confirmed that updating the modelling of Option 2 to reflect a rating of at least 152 MVA (summer day) without changing other line parameters will not significantly reduce the

Summary of comment(s)	Submitter(s)	Our response
		gross market benefits. For a more detailed explanation see Section 3.4.
The stakeholder noted the upcoming release of the new ISP scenarios and the potential to undertake additional market analysis based on these updated scenarios. However the stakeholder considers that any change in the ISP scenarios is unlikely to result in a different conclusion and the additional time and cost of additional analysis is likely not justified.	p.2	We consider additional modelling to account for the new assumptions is not required given that Option 2 is the preferred solution under almost all scenarios, and additional modelling would impose additional time and costs on a relatively small project. It would also delay the start of detailed design work on the preferred solution and potentially push back the delivery of the solution. As outlined in the RIT-T, Line 94T is currently one of the top binding constraints on the network and any delay in delivering a solution will create additional costs to the market.
The stakeholder believes Transgrid should more closely investigate the impact of the delivery timeline in an updated analysis before the release of the Project Assessment Conclusions Report.	p.2	We consider that bringing forward the proposed solutions is unlikely to alter the relative rankings of the solutions. We will consider further timing decisions as we undertake a more detailed design assessment of the preferred option following the conclusion of this PACR.

Summary of comment(s)	Submitter(s)	Our response
The stakeholder raised the possibility of oversizing the current preferred solution to be robust to future capacity growth.	p.3	The preferred solution is the highest rating that we can achieve using the existing structures. In reaching this decision, we have taken into account any structural strengthening that will be required and the additional delay in construction and commissioning that would result from increasing the rating further.
Submission 2 – Conductor manufacturer		
The stakeholder supported Option 2A which would increase the summer daytime thermal rating from 112 MVA to at least 152 MVA.	p.1	We note the preference of the conductor manufacturer. Option 2 has been chosen over Option 2A as it produces a higher net present value across all scenarios and sensitivities in comparison to Option 2A.
Submission 3 - Unknown		
The stakeholder considers that Transgrid should include a long term plan to increase system strength in the region to complement the increase in capacity.	p. 1-5	We consider the issues identified by the stakeholder and their proposed solution (which includes a new 330kV network extension to the Cowra substation) are outside the scope of this

Summary of comment(s)	Submitter(s)	Our response
The current RIT-T PADR for increasing capacity for generation in the Molong-and Parkes area focuses only on resolving the constraint on the 132 kV feeder 94T running between Molong and Orange North. However, it fails to address low system strength issues and network constraints in the large high renewable energy resource region west of Bathurst.		particular RIT-T process, which is limited to addressing the identified need as presented in Section 2.1. We are taking steps to identify and address system strength and network constraints in other parts of the network in central west New South Wales. This includes through the BOP RIT-T, which involves the use of a non-network solution provided via a 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. It also includes the Meeting system strength requirements in NSW RIT-T, which seeks to provide the minimum and efficient levels of system strength forecast by AEMO at each of the NSW system strength nodes from 2 December

Summary of comment(s)	Submitter(s)	Our response
		2025. It also seeks to address a system strength shortfall declared by AEMO from 1 July 2025 to 1 December 2025 at Newcastle and Sydney West. We consider that Option 2 remains the preferred solution for addressing the identified need.
The RIT-T should recognise that a larger quantity of projects will be developed West of Molong, beyond those listed in the PSCR and that these should be included in the analysis.	p.3-4	We note that all generation projects that met the definition of committed or anticipated generators at the time market modelling was conducted for this RIT-T have been included.

Appendix C 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.

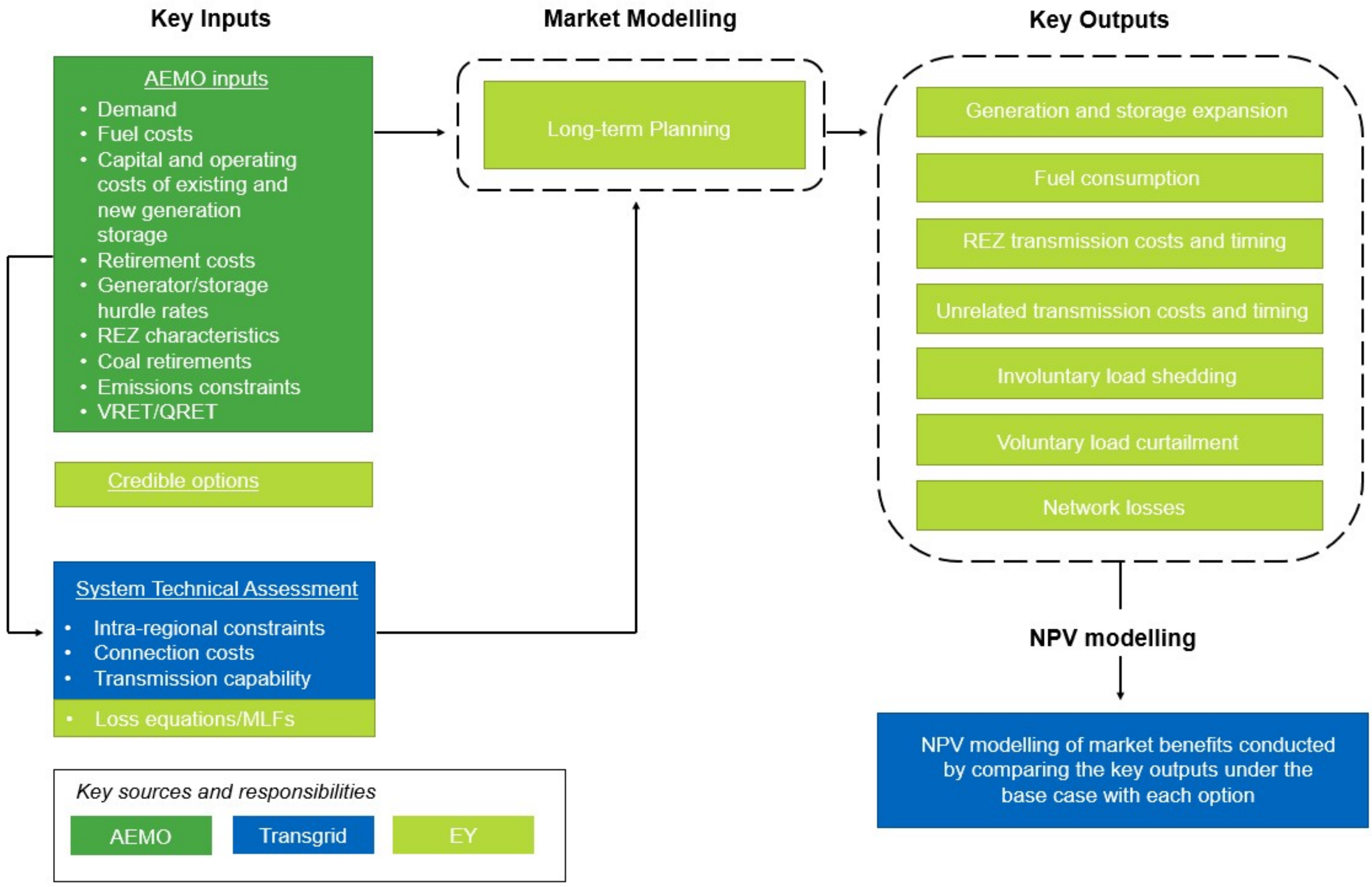
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term market modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving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

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

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP. For further detail, refer to the EY market modelling report.

Figure 8-1 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 8-1 Overview of the market modelling process and methodologies



The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PACR 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 budget 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.[19]

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.

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

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

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

Modelling of diversity in peak demand

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

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

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

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

Modelling of intra-regional constraints

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

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

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model.

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 8-2 Summary of the credible options

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ISP 2022 – Step Change	ISP 2022 – Progressive Change	ISP 2022 – Hydrogen Superpower
Committed and anticipated generation	AEMO Generation information data as of January 2023		
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
Retirements of coal-fired power stations	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes
Gas fuel cost	2021 Inputs and Assumptions Workbook - Step Change	2021 Inputs and Assumptions Workbook - Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
Coal fuel cost	2021 Inputs and Assumptions Workbook - Step Change	2021 Inputs and Assumptions Workbook - Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
NEM carbon budget	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 VRET2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50% by 2030		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040, excluding hydro		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	2022 ISP: EnergyConnect commissioned by July 2026		
Western Renewable Link	Western Renewables Link commissioned by July 2026		
HumeLink	2022 ISP outcome – Step Change: HumeLink commissioned by July 2028	2022 ISP. outcome – Progressive Change: HumeLink commissioned by July 2035	2022 ISP. outcome – Hydrogen Superpower: HumeLink commissioned by July 2027
Marinus Link 1	2022 ISP outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	QNI minor commissioned by July 2022		
QNI Connect	2022 ISP outcome – Step Change: QNI Connect commissioned by July 2032	2022 ISP outcome – Progressive Change: QNI Connect commissioned by July 2036	2022 ISP outcome – Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030

VNI West	2022 ISP outcome – Step Change: VNI West commissioned by July 2031	2022 ISP outcome – Progressive Change: VNI West commissioned by July 2038	2022 ISP outcome – Hydrogen Superpower: VNI West commissioned by July 2030
Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.		
New England REZ Transmission	2022 ISP outcome – Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP outcome – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP outcome – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 2 by July 2042
Snowy 2.0	Snowy 2.0 is commissioned by December 2027		