Transgrid

People. Power. Possibilities.

Meeting system strength requirements in NSW

RIT-T Project Assessment Draft Report (PADR)

Region: New South Wales

Date of issue: 17 June 2024

Executive Summary

Transgrid is responsible for ensuring sufficient system strength services are available to maintain the stability of the NSW power system.

The retirement of NSW's coal generators and the growth in inverter-based resources in the coming decade is driving an urgent need to add new sources of system strength to the power system.

A network without adequate system strength will result in stability issues. Generators may be unable to remain connected during disturbances on the power system, control of the system voltage becomes more difficult, and protection systems that ensure safe operation of the network may not operate correctly. Insufficient system strength raises the risk of system instability and supply interruptions to end consumers.

This Project Assessment Draft Report (PADR) assesses over 100 non-network and network solutions to identify several 'portfolio options' that are designed to meet our system strength obligations and maximise the present value of net economic benefit to the National Electricity Market (NEM).

Identified need: meeting system strength requirements in NSW

Transgrid, as the System Strength Service Provider (SSSP) for NSW, is responsible for ensuring sufficient system strength services are available to maintain power system stability in NSW. We are applying the Regulatory Investment Test for Transmission (RIT-T) to options that meet our National Electricity Rule (NER) obligations, specifically:

1. Clause 11.143.15 to address a system strength Shortfall in the transmission network at Newcastle and Sydney West, forecasted to arise from 1 July 2025 and continue until 1 December 2025; and

2. Clause S5.1.14 to deliver system strength services to the NSW power system to meet standards set by AEMO from 2 December 2025, including for the safe and secure operation of the power system (minimum level) and to facilitate the stable voltage waveform ('efficient' level) of new inverter-based resources (IBRs).

This RIT-T examines non-network and network options to ensure compliance with system strength requirements in the National Electricity Rules (NER) and to maximise the present value of net economic benefit to the National Electricity Market (NEM) and ultimately to the consumers.[1]

The PADR has benefited from stakeholder submissions

Publication of this PADR is the second step in the RIT-T process. It follows publication of the Project Specification Consultation Report (PSCR) on 16 December 2022, which received five submissions, together with an accompanying Expression of Interest (EOI) from potential third-party system strength proponents (i.e. entities that could provide system strength services to Transgrid under a network support contract).

Overall, the analysis presented in this PADR has been strongly informed by this consultation, which has helped ensure the robustness of the analysis. We thank all parties for their valuable input to the consultation process to date.

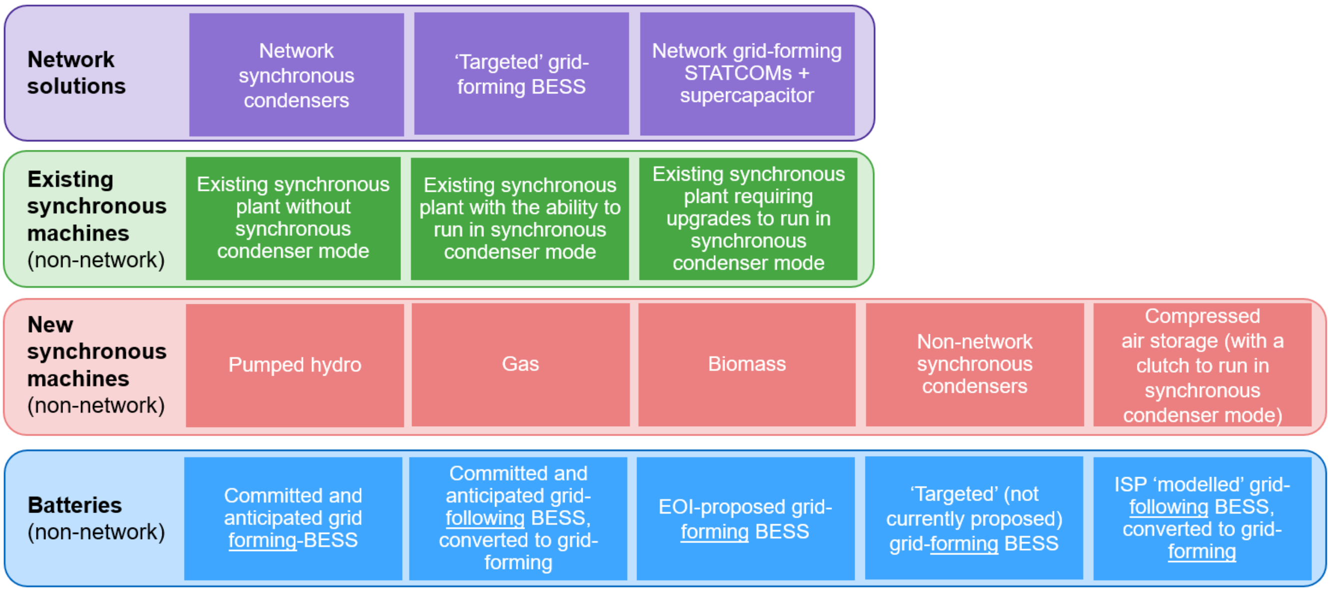
[1] This is a 'reliability corrective action' under the RIT-T as the options considered are for the purpose of meeting externally imposed regulatory obligations and service standards, i.e., Clauses 11.143.15 and S5.1.14 of the NER.

The EOI process resulted in non-network option submissions from 25 parties, covering over 60 individual potential technology solutions, including:

- a pipeline of more than 10 GW of innovative grid-forming batteries;
- over 5 GW of other new generation and energy storage projects, including pumped hydro and gas; and
- over 10 GW of existing or conversions of existing synchronous generators.

Transgrid has also developed 40 unique network solutions (where Transgrid would manage and operate the asset).

Figure E.1 – Summary of the types of solutions considered within this PADR



Developments since publication of the PSCR

System strength requirements in the NEM are driven by AEMO's annual System Strength Report, which specifies minimum fault level requirements and a ten-year forecast for IBRs connecting in the NEM.

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the amount of IBR that AEMO forecasts to connect to the NSW power system in the next decade has changed, driven by updates from AEMO's Draft 2024 Integrated System Plan (ISP). In addition, Transgrid's system strength requirements have also changed because EnergyCo has confirmed ACEREZ, the Network Operator for the Central West Orana REZ stage 1, will centrally procure system strength for the REZ.

We also note that on the 22 May 2024 (following the conclusion of our PADR market modelling), the NSW Government and Origin Energy agreed to extend the life of the Eraring Power Station by two years, to 30 June 2027.[2]

[2] Eraring's extension is likely to result in the reduction or closure of the system strength Shortfall that AEMO has declared for Sydney West and Newcastle from July to December 2025. Our PACR (and intermediate RIT-T re-opening trigger consultation document) will reflect any updates to the Shortfall declaration and implications of Eraring's two-year extension on the optimal portfolio of solutions.

In May 2024, AEMO published its Update to the 2023 Electricity Statement of Opportunities, which stated that minimum fault level requirements "*must be delivered by devices that can provide protection-quality levels of fault current – such as new synchronous condensers, service contracts with existing hydro or thermal units, or through the retrofit of those existing units themselves.*"[3]

As part of preparing this PADR, Transgrid also engaged Aurecon to undertake an assessment of the maturity of grid-forming BESS to provide system strength support. Aurecon concluded[4] that there is insufficient evidence (either at-scale deployments or in modelling) to rely on grid-forming BESS to support minimum fault level requirements (until 2032/33). Aurecon also concluded that grid-forming BESS are sufficiently mature to provide stable voltage waveform support to new connecting IBRs. This advice has informed Transgrid's PADR modelling.

PSCAD models will be required from proponents following the PADR publication, in order to validate proposed plant performance against Transgrid's technical requirements. These studies are required before the plant can be considered part of the optimal portfolio of solutions at the final Project Assessment Conclusions Report (PACR) stage.

Since the PSCR publication, there have been other dynamics that have influenced this RIT-T, including an evolving regulatory environment[5] and supply chain challenges associated with synchronous condensers.[6]

Our approach to identifying the preferred 'portfolio of solutions'

While it is common for RIT-Ts to identify a 'preferred option' (i.e., singular) to meet the need, the scale and complex nature of NSW's system strength requirements necessitated a preferred 'portfolio of solutions'. This was because:

- the need for system strength must be co-optimised across six system strength 'nodes' in NSW and at the connection points of all future IBRs;
- no single solution can meet the need – in fact, dozens of solutions across NSW will be required at any one time;
- we assessed over 60 individual non-network solutions and 40 unique network solutions to meet the need – resulting in billions of combinations of possible solutions; and
- the system strength contribution of each asset to each system strength node (and points of IBR connections) is dynamic and non-linear, changing at any one time depending on the combination of solutions online and the impedance of the network.

We developed a power system and market modelling methodology to account for these drivers of complexity and to enable us to identify optimal portfolios of solutions to meet our system strength

3 AEMO, *Update to the 2023 Electricity Statement of Opportunities*, May 2024, p. 43.

4 Aurecon, Advice on the maturity of grid forming inverter solutions for system strength, April 2024.

5 For example, at the time of commencing market modelling in mid-2023, Energy Ministers had agreed to update the NEO to incorporate an emissions reduction objective, which was followed later by an AEMC rule change which required RIT-Ts to consider the value of changes in greenhouse gas emissions. The Value of Emissions Reduction was published in late March 2024. In parallel, the AEMC was consulting on the 'Operational Security Mechanism' rule change (which concluded in March 2024 under a new name, 'Improving Security Frameworks for the energy transition'), which included rules on the enablement and settlement of system strength services in the operational timeframe and changes to the inertia framework.

6 The global demand for synchronous condensers is increasing as a result of growing system strength requirements across the world, including in Australia, northern Europe (as a result of offshore wind deployments), UK and USA. Global manufacturing capacity is limited, leading to increased costs and lead-times.

requirements in the coming two decades. All 100 individual options proposed by non-network proponents and Transgrid were assessed as part of this.

Our methodology integrates system strength constraints into market modelling software (PLEXOS) and uses its Long-Term capacity expansion capabilities to optimise and trade-off the deployment of new build options that provide system strength, with a change in the operating patterns for existing synchronous machines. The process finds the optimal 'portfolio of solutions' which maximise net market benefits while meeting system strength requirements. It does this in a similar way to what AEMO does in its ISP, to identify the optimal timing and mix of generation assets, storage and transmission.

In addition, in order to tune system strength 'coefficients' used within PLEXOS, and to validate that the output of PLEXOS' portfolio optimisation met the power system's needs, PLEXOS results were automatically analysed within PSS®E, with a full network topology including geographically dispersed IBR locations. This process meant tens of thousands of power system modelling simulations occurred to validate the portfolios of solutions.

Although typical for RIT-Ts to assess options against AEMO's Step Change, Progressive Change and Green Energy Exports scenarios, this PADR assesses our portfolios of options against a single scenario – the Step Change scenario. This is because our stable voltage waveform requirements are driven by AEMO's ten-year forecast of IBRs, which in turn has been driven by Step Change scenario. Assessing our portfolios of options against other ISP scenarios would be akin to varying our obligations itself.

Instead, we have developed additional 'portfolio option' sensitivities where we have assessed targeted variations in the need itself, such as a state of the world where all batteries in AEMO's IBR forecasts self-remediate (by using grid-forming inverters) or where several REZs are self-remediated by a third-party network operator (i.e., rather than Transgrid).

The optimisation process considered multiple 'portfolio options'

The PADR portfolio optimisation process considered all 100 non-network and network solutions using specialist market modelling and power system analysis software. The objective was to identify optimal portfolios of options (termed 'portfolio options') which met our system strength requirements and provide the greatest net benefits to the energy market.

Different portfolio options were created by varying key input assumptions:

- the earliest timing that synchronous condenser could be commissioned; and
- the technical feasibility of a confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West (where the technical feasibility has not yet been demonstrated); and
- constraining the solution by assuming fewer gas units are able to be contracted with to provide system strength services.

The four portfolio options developed can be summarised as follows:

- **Portfolio option 1:** synchronous condensers able to be commissioned in 2028/29; and
- **Portfolio option 2:** synchronous condensers able to be commissioned a year earlier in 2027/28 (i.e., 'accelerated'); and

- **Portfolio option 3:** portfolio option 1 assumptions plus the confidential proposal *is* assumed to be technically feasible; and
- **Portfolio option 4:** portfolio option 1 assumptions but with the addition of a restriction on the number of gas units we can contract with.

Credibility of the four portfolio options

At this stage, only portfolio option 1 and portfolio option 4 are considered credible options. This is because our current best available information suggests that:

- the earliest timing that synchronous condensers could be commissioned is in 2028/29. Acceleration (to 2027/28) is expected to only be feasible if we commence procurement of synchronous condensers prior to the conclusion of the RIT-T and AER's approval of a contingent project application (CPA);
- the technical feasibility of a confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West has not yet been demonstrated by the project proponent.

However, insights from our market modelling show that if these two options were proven to be feasible, there would be significant additional benefits for consumers. As such, we will work over the course of this RIT-T to clarify and resolve the uncertainties associated with the possible acceleration of synchronous condensers and the technical feasibility of the confidential proposal.

Composition of the four portfolio options

Portfolio option 1

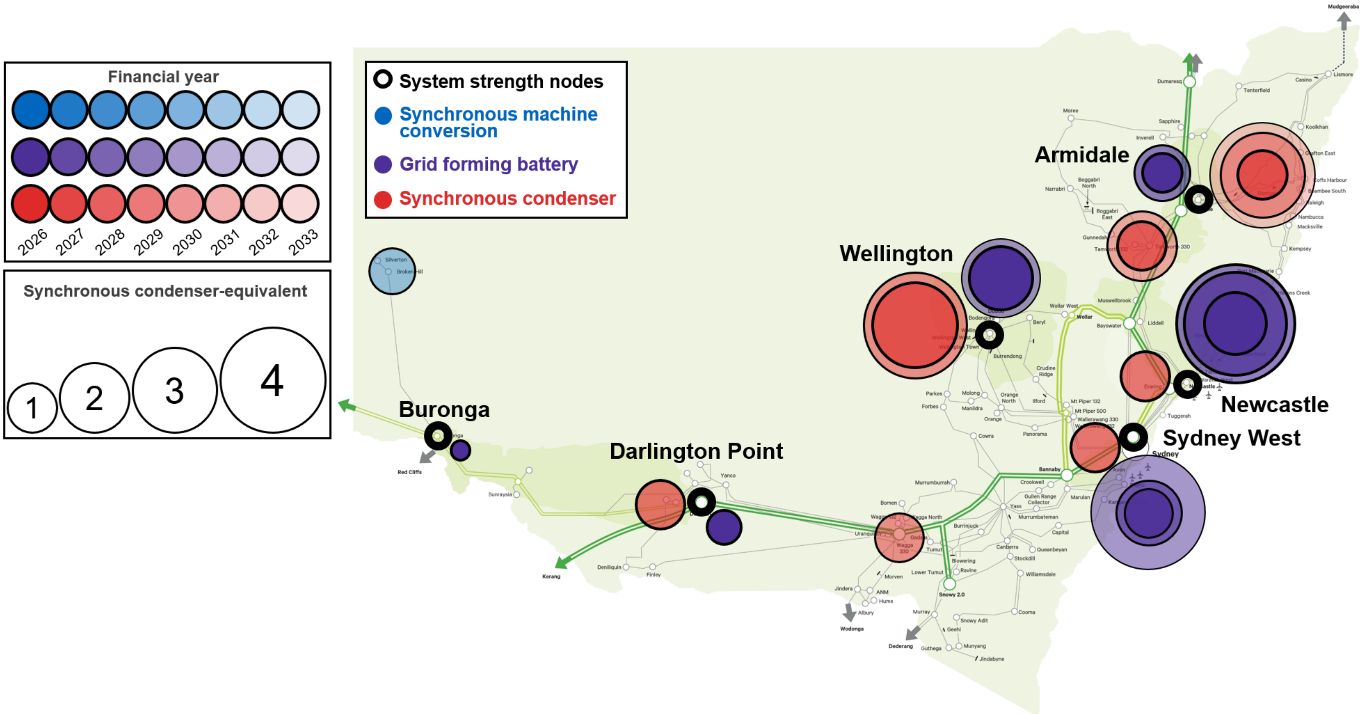
Portfolio option 1 is made-up of:

- fourteen synchronous condensers required by the end of the next regulatory period (2032/33), with eight of these required by 2028/29;
- modifications to synchronous hydro generators and the addition of clutches to the Broken Hill compressed air energy storage facility in order to facilitate system strength provision even when the units are not generating, pumping or compressing, in total contributing over 550 MW of generation assets;
- re-dispatching[7] a range of existing hydro generators to ensure they can switch on or operate in synchronous condenser mode where necessary to fill gaps in system strength, as well as a smaller number of gas and black coal units also being re-dispatched; and
- 4.8 GW of new build grid-forming BESS by 2032/33, comprising primarily of upgrading committed and anticipated grid-following BESS with grid-forming capability and ISP 'modelled' BESS included in AEMO's IBR forecasts also upgrading to grid-forming capability.

The figure below provides a summary of the magnitude, location and timing of the new build components (or conversions) making up portfolio option 1.

[7] The word 're-dispatched' or 're-dispatching' has been used to represent system strength solutions (typically existing or future synchronous generators) which are 'enabled' or 'scheduled-on' by AEMO for the purpose of providing system strength services.

Figure E.2 – New build prior to 2032/33 under portfolio option 1



Note: This figure does not show the re-dispatch of existing machines, which are also included in this portfolio option. It also excludes selected system strength solutions for confidentiality reasons.

Under portfolio option 1, our modelling results show that there are gaps in system strength that cannot be filled in 2027/28. These gaps occur at or surrounding Armidale, Wellington, Newcastle, Sydney West and Darlington Point nodes during times when there are low numbers of synchronous machines online due to synchronous generator maintenance or outages (occurring for up to 3% of time in the year). These gaps are exacerbated when individual transmission lines between Newcastle and Armidale are required to be out of service for short periods of time for maintenance or for the connection of new transmission projects.

While portfolio option 1 is currently the most credible option, Transgrid will work to identify other portfolio options (and, in particular, portfolio options 2 and 3, independently or together), which close the system strength gap in 2027/28 and deliver greater overall net market benefits to consumers.

Portfolio options 2 – 4

All portfolio options contain a blend of non-network (e.g. coal, hydro, gas, grid-forming batteries) and network (e.g. synchronous condensers) system strength solutions. Portfolio options 2 to 4 represent variations on portfolio option 1, as a result of varying a key assumption within the portfolio optimisation process.

The table below compares the composition of portfolio options 2 to 4, compared to portfolio option 1.

Table E.1 – Composition of portfolio options 2-4, compared to portfolio option 1

Option component	Portfolio option 2 – synchronous condensers in 2027/28	Portfolio option 3 – confidential proposal assumed to be technically feasible	Portfolio option 4 – restricting the number of gas units
Synchronous condensers	Brings forward five synchronous condensers by one year, from 2028/29 to 2027/28. Identical build path of synchronous condensers from 2028/29 onwards (14 required by 2032/33).	Requires four less synchronous condensers by 2032/33. No synchronous condensers required at Sydney West and Newcastle, as well as deferred requirements for synchronous condensers at Tamworth, and within the New England REZ and the CWO REZ.	Brings forward two synchronous condensers by one year, from 2029/30 to 2028/29 and adjusts the timing of two other synchronous condensers between 2031/32 and 2034/35. The same number of synchronous condensers is required over the modelling period (26 in total).
Modifications to synchronous generators	Identical levels of modifications to existing or future synchronous machines are required.		
Re-dispatch of synchronous machines	Similar dispatch of synchronous machines. Decrease coal, hydro and gas operation in 2027/28 due to earlier deployed synchronous condensers.	Near term reduction of coal and gas dispatch pre-2028/29 due to confidential proposal. Initially less hydro operation pre 2037/38 before increasing for the remainder of the horizon.	Similar dispatch of synchronous machines. Coal and gas run less in 2027/28 due to less units available to contract for system strength
Grid-forming BESS	Effectively the same levels of grid-forming BESS are required (i.e., only minor changes for these three portfolio options).		

With regards to gaps in system strength observed in portfolio option 1, the following options contribute towards removing these gaps:

- Portfolio option 2 (if synchronous condensers are available one year prior, in 2027/28) closes all system strength gaps that our model shows in 2027/28; and
- Portfolio option 3 (if the confidential proposal is proven to be technically feasible) closes the system strength gaps in nearby locations (Sydney West and Newcastle regions) but does not close the gaps at the further locations (Armidale, Wellington and Darlington Point).

Expected cost of the portfolio options

Given the magnitude of the identified need, there are significant costs associated with meeting system strength needs across the four portfolio options.

In undiscounted 2023/24 dollars, we estimate that portfolio option 1 has total costs between now and the end of the next regulatory control period (i.e., out to 2032/33):[8]

- $1,375 million capital costs and $28 million operating costs for new synchronous condensers;

[8] Please note that these costs do not map directly to the costs Transgrid expects to recover via the regulatory control process (e.g., the unit upgrades to allow synchronous condenser mode operation and new grid-forming BESS build would be incurred by proponents of these solutions who would then charge Transgrid an operating cost to cover their costs). We have presented costs over this period here since investment decisions regarding the number of network synchronous condensers required by the end of next regulatory control period are expected to be made as a result of the outcomes of this RIT-T.

- $25 million capital costs and $0 million in incremental operating costs for unit upgrades to allow synchronous condenser mode operation; and
- $360 million capital costs and $10 million operating costs for grid-forming BESS.

Table E.2 summarises the total capital and operating costs[9] for each option over the full 20-year assessment period, in aggregate across the difference components (please note that these costs are shown in *undiscounted* 2023/24 dollars).

Table E.2 – Summary of the costs of the four portfolio options over the 20-year assessment period – undiscounted 2023/24 dollars, $m

	1 – Synchronous condensers available from 2028/29	2 – Synchronous condenser delivery accelerated to 2027/28	3 – Confidential proposal technically feasible	4 – Restricting the number of gas units
New synchronous condensers				
Capex	$2,023	$2,023	Confidential*	$2,023
Opex	$144	$147		$144
Total	**$2,167**	**$2,170**		**$2,167**
Unit upgrades to allow synchronous condenser mode operation				
Capex	$25	$25	Confidential*	$25
Opex	$0	$0		$0
Total	**$25**	**$25**		**$25**
Grid-forming BESS				
Capex	$360	$357	Confidential*	$352
Opex	$28	$28		$28
Total	**$388**	**$384**		**$380**
Total costs (excl. re-dispatch)				
Capex	**$2,408**	**$2,404**	**Confidential***	**$2,399**
Opex	**$172**	**$175**		**$172**
Total	**$2,580**	**$2,579**		**$2,571**

** Portfolio option 3's costs have been redacted given it includes the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West.*
Note, costs may not add due to rounding.

All portfolio options involve operating (fuel) costs for re-dispatching existing synchronous machines to provide system strength. While these costs are not able to be separated out from general dispatch costs in the market modelling, we note that, in aggregate and in present value terms, portfolio option 1 is estimated to involve approximately $7,775 million *lower* total fuel costs than the base case (i.e., the 'do nothing' reference point that all portfolio options are required to be assessed against under the RIT-T). This

[9] In preparing this PADR, Transgrid has used the best available information on the timing and costs of non-network and network solutions, as established in mid-2023 following the PSCR consultation and expressions of interest phase, and detailed proponent and Original Equipment Manufacturer (OEM) discussions. Transgrid is continuing to engage with proponents and OEMs on the lead times and costs of all proposed solutions. Market modelling for the PACR stage of the RIT-T will incorporate latest information as it arises.

accounts for both the greater costs for re-dispatch and the avoided dispatch costs generally. The other portfolio options have similar levels of total fuel costs in aggregate and are also lower than the base case.

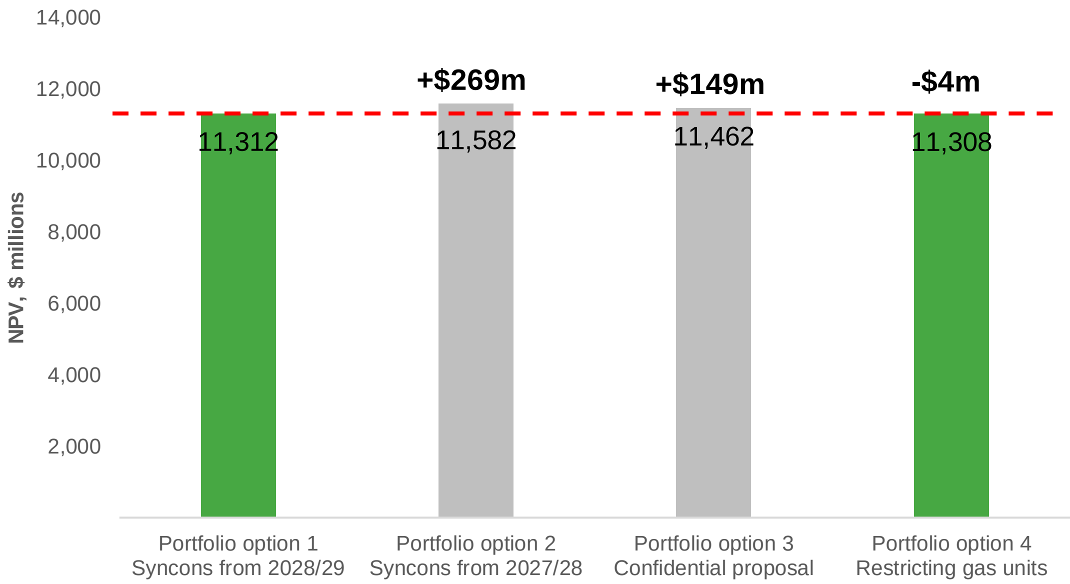
Our modelling shows that non-network solutions will play a core role in providing system strength into the future, and will be brought into the portfolio of solutions via network support contracts. While network support contract costs are treated as a wealth transfer under the RIT-T (and so have no bearing on the results),[10] we know that network support contract costs will have a crucial impact on the ultimate cost to end consumers and the AER will be explicitly determining whether such costs are prudent and efficient as part of an ex-ante assessment. As such, the PACR will investigate approaches for minimising these costs, where possible, without materially impacting the make-up of the ultimately preferred option.

As input into the PACR market modelling, Transgrid will assess the technical and commercial credibility of all non-network options selected as part of the PADR's preferred portfolio of solutions (which were assumed to be technically and commercially credible). Where non-network solutions are determined to not be credible, these options will not progress through the RIT-T and procurement process. Alternative solutions (either non-network or network) would be required to fill its place in the optimal portfolio of solutions.

Preferred portfolio option(s)

The Net Present Value (NPV) results demonstrate that the ultimately preferred option for this RIT-T will depend on what can be confirmed as feasible through the PADR consultation process. The figure below summarises the headline NPV results for each of the portfolio options, as well as a comparison to portfolio option 1 for portfolio options 2-4.

Figure E.3 – Headline NPV results for each of the portfolio options. Green indicates currently credible portfolio option; grey indicates a portfolio option where investigation will continue over the course of the RIT-T to see whether credibility can be confirmed.



[10] AER, *Regulatory investment test for transmission – application guidelines*, Final decision, October 2023, pp 60-62.

Portfolio option 1 is found to generate substantial estimated net benefits over the assessment period – approximately $11.3 billion in present value terms.[11] However, there are still gaps in system strength that cannot be filled in 2027/28 under this option, which presents risks to outcomes for the power system and consumers (including expected unserved energy).

Importantly, while portfolio option 1 is currently the most credible option, the PADR analysis finds that:

- if the delivery of synchronous condensers can be accelerated by one year (i.e., under portfolio option 2), gaps in system strength are eliminated and the expected net market benefits *increase* by approximately $269 million (in present value terms) over the assessment period;

- if the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West was in fact technically feasible (i.e., under portfolio option 3), the expected net market benefits *increase* by approximately $149 million (in present value terms) over the assessment period compared to portfolio option 1. Note that this proposal closes the system strength gap in nearby locations (Sydney West and Newcastle regions) but does not close the gap at the further locations (Armidale, Wellington and Darlington Point).
- if we restrict the number of gas units assumed to be contracted with for system strength, then the expected net market benefits decrease by approximately $4 million (in present value terms) over the assessment period compared to portfolio option 1. This is driven in part by a slight increase in system strength gaps that occur in 2027/28 and slight changes to the timing of new-builds, compared to portfolio option 1.

In addition to increased market benefits for consumers and a reduction in system strength gaps, accelerating the procurement of synchronous condensers (as per portfolio option 2) also provides insurance against the risk of further synchronous condenser supply chain delays, early coal retirements and reduces the dependence on higher emissions synchronous machines for system strength.

While grid-forming batteries have not been sufficiently demonstrated (at scale or in modelling) to provide protection-quality levels of fault current, a portfolio of 4.8 GW of grid-forming batteries supporting stable voltage waveform will provide Transgrid with a measured and safe approach to test and build confidence in the capabilities of grid-forming batteries for fault current support. This is necessary before Transgrid will consider this technology suitable for meeting minimum fault level requirements.

Next steps

While portfolio option 1 is currently the most credible and preferred portfolio option at this stage of the RIT-T, net market benefits would significantly increase if portfolio option 2 (accelerated synchronous condensers) or portfolio option 3 (confidential proposal) were proven to be feasible. As such, there is significant merit in continuing to investigate whether the key uncertainty involved with each can be resolved over the course of this RIT-T, individually or in combination.

Specifically, between now and the PACR, we will:

[11] Net market benefits of each portfolio option are assessed against a ‘do nothing’ base case (or counterfactual scenario), in line with RIT-T requirements. A ‘do nothing’ scenario would mean that Transgrid does not procure any system strength solutions to meet its need, which would ultimately lead to significant system strength violations, and ultimately unserved energy for consumers.

- investigate the advancement the procurement and commissioning of ‘no-regret’ synchronous condensers. This would require commencement of procurement of synchronous condensers prior to the conclusion of the RIT-T and AER’s approval of a contingent project application (CPA);
- confirm the technical feasibility of the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West. We work with the proponent of this solution following this PADR to determine this;
- identify credible approaches to minimise expected network support payments without materially impacting the optimal portfolio of solutions (e.g., contracting with less gas, coal or hydro units);
- identify additional non-network solutions that can contribute to meeting system strength gaps at Armidale, Sydney West, Newcastle, Wellington and Darlington Point in 2027/28. These additional non-network solutions must be capable of providing protection-quality levels of fault current, such as new synchronous condensers, new synchronous generators or modifications to existing units; and
- assess the technical feasibility of each proposed grid-forming battery project via a request for PSCAD models (which is considered necessary before each project can be considered part of the optimal portfolio of solutions at the final PACR stage).

The outcomes of these will be included in the ultimately preferred option of this RIT-T.

Submissions

We welcome written submissions on materials contained in this PADR.

Submissions are due on 2 August 2024.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[12] In the subject field, please reference ‘Meeting system strength requirements in NSW RIT-T PADR’.

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

Contents

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1 Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options that:

1. address a system strength Shortfall in the transmission network declared by AEMO at Newcastle and Sydney West that is forecast to arise from 1 July 2025 until 1 December 2025; and
2. deliver system strength services to the NSW power system to meet the minimum and efficient standards set by AEMO from 2 December 2025, as reflected in the AEMO December 2023 System Strength Report.

We are required under the NER to provide these system strength services to maintain the safety, security and reliability of the power system.

We are assessing options that can continue to provide system strength services outside of the three-year binding period required under our obligation (currently out to 1 December 2027), as this represents the most efficient, and only plausible approach to the procurement of these services, which will be required on an on-going basis.

On 1 December 2023, AEMO published revised (increased) Shortfalls of 1,420 MVA and 1,165 MVA at Newcastle and Sydney West, respectively, as part of the 2023 System Strength Report.[13] On 20 December 2023, AEMO gave a revised notice to Transgrid under clause 11.143.14 of the NER covering these increased Shortfalls.

Under clause 11.143.15 of the NER, Transgrid is responsible for making system strength services available to address the expected system strength Shortfall identified by AEMO in its notice. We note that following the agreement between the NSW Government and Origin Energy for the extension of the life of Eraring Power Station to July 2027, AEMO is expected to revise the currently declared Shortfall. Transgrid will take into account any Shortfall revisions at the PACR stage.

From 2 December 2025 onwards, a new system strength framework will commence under the NER. Under the new framework, Transgrid is required to act as a System Strength Service Provider (SSSP), and is responsible for planning and operating our network to ensure there is sufficient system strength available in the NSW power system to meet the standard required by AEMO. The 2022 System Strength Report provided the first of AEMO's assessments under the new framework, including the 10-year IBR forecast for each system strength node declared (which is to be used by SSSPs for the purposes of meeting the efficient level of system strength).[14] This assessment has been subsequently updated in AEMO's 2023 System Strength Report.

AEMO has indicated that where a Shortfall overlaps with the introduction of the new system strength framework i.e., a Shortfall occurs after 1 December 2025, SSSPs are expected to address Shortfalls as part of its overall delivery against the new system strength framework.[15]

Publication of this Project Assessment Draft Report (PADR) is the second step in the RIT-T process. It follows publication of the Project Specification Consultation Report (PSCR) on 16 December 2022, together with an accompanying Expression of Interest (EOI) seeking non-network options from potential third-party

[13] AEMO, *2023 System Strength Report*, December 2023, p. 3.
[14] AEMO, *2022 System Strength Report*, December 2022, p. 15.
[15] AEMO, *Update to 2021 System Security Reports*, May 2022, p. 4

system strength contractors (i.e. entities that could provide system strength services to Transgrid under a network support contract).

On 25 January 2024, Transgrid sought an extension of time to publish the PADR for this RIT-T from 31 March 2024 to 30 June 2024. This request was made in light of the opportunity to incorporate materially updated IBR forecasts from the 2023 AEMO System Strength Report, as well as delays to important key related external developments (for example the Operational Security Mechanism rule change, as it was previously named) and the need to develop a complex market dispatch model that includes system strength constraints. On 27 March 2024, the AER granted this extension.

The nature of NSW's system strength requirements necessitated an advanced market modelling approach for this PADR, because:

- the need for system strength must be co-optimised across six system strength 'nodes' in NSW and at the connection points of all future IBRs;
- no single solution can meet the need – in fact, dozens of solutions across NSW will be required at any one time;
- we assessed over 60 individual non-network solutions and 40 unique network solutions to meet the need – resulting in billions of combinations of possible solutions; and
- the system strength contribution of each asset to each system strength node (and points of IBR connections) is dynamic and non-linear, changing at any one time depending on the combination of solutions online and the impedance of the network.

There are also other dynamics to account for including an evolving regulatory environment[16], supply chain challenges with regards to synchronous condensers[17] and varying levels of maturity of system strength solutions.

As a consequence, we were required to consider the most appropriate way to undertake the RIT-T assessment to develop a transparent and robust conclusion, whilst also ensuring that the analysis remains tractable across the large number of potential solutions put forward and the various uncertainties around technological feasibility and future market development.

In response, we have developed a robust power system and market modelling methodology to enable us to identify the optimal portfolio of solutions to meet our system strength requirements in the coming decade. The methodology has been developed to integrate system strength constraints into market modelling software (PLEXOS). The use of the Long-Term capacity expansion capabilities of the software maximises market benefits while meeting system strength constraints, balancing between the deployment of new build options and the change of dispatch of existing synchronous machines. The introduction of system strength into Long-Term market modelling identifies the optimal portfolio of system strength solutions, in a process that reflects the methodology for AEMO's Integrated System Plan to identify ideal timing and mix of generation assets, storage and transmission.

In addition, in order to tune system strength 'coefficients' used within PLEXOS, and to validate that the output of PLEXOS' portfolio optimisation met the power system's needs, PLEXOS results were automatically analysed within PSS®E, with a full network topology including geographically dispersed

[16] For example, at the time of commencing market modelling in mid-2023, Energy Ministers had agreed to update the NEO to incorporate an emissions reduction objective, which was followed later by an AEMC rule change which required RIT-Ts to consider the value of changes in greenhouse gas emissions, however no Value of Emissions Reduction was published until late-March 2024. In parallel, the AEMC was consulting on the 'Operational Security Mechanism' rule change (which concluded in March 2024 under a new name, 'Improving Security Frameworks for the energy transition'), which included rules on the enablement and settlement of system strength services in the operational timeframe and changes to the inertia framework.

[17] The global demand for synchronous condensers is increasing, as a result of growing system strength requirements across the world, including in Australia, northern Europe (as a result of offshore wind deployments), UK and USA. Global manufacturing capacity is limited, leading to increased costs and lead-times.

IBR locations. This process meant tens of thousands of power system modelling simulations occurred in order to validate the portfolios of solutions.

Our approach is consistent with our regulatory requirements and accepted market modelling practise, with changes made to best optimise project outcomes in light of the complexity and scale of the problem.

This RIT-T examines network and non-network solutions to ensure compliance with system strength requirements in the NER and provide the greatest net economic benefit to the energy market. The options assessed represent portfolios of network and non-network solutions (rather than options with a single solution). This reflects the scale and geographical breadth of the identified need, and because of the number of network solutions and non-network solutions proposed in response to the PSCR and the accompanying EOI.

While Transgrid's obligation to meet the standard under Clause S5.1.14 from 2 December 2025 includes a three-year binding period, currently to 1 December 2027,[18] we consider it will be most efficient to consider solutions that can continue to provide system strength beyond this period. This is due to the complexity and timeframe involved in both the RIT-T and procurement processes as well as the inherent long-term ability of the solutions proposed to provide system strength. We therefore are notionally aiming to procure solutions for nine years into the future (i.e., out to 2032/33 inclusive) following completion of this RIT-T.

Further, we have assessed all solutions over a twenty-year assessment period consistent with the typical assessment period for RIT-Ts where wholesale market modelling is required. Components of the options later in this period are currently considered on an indicative basis only and would be subject to a later RIT-T and procurement process.

Following the conclusion of this RIT-T, we will be monitoring system strength requirements and may need to commence a new RIT-T if there is a significant change in the requirements relative to what has been catered for in the preferred option coming out of this RIT-T. However, we note that the portfolio options assessed in this RIT-T involve flexibility to be able to ramp up and down the provision of system strength as the forecasted need changes, in order to mitigate the need to conduct a new RIT-T (and associated procurement process) in the next few years.

Consistent with the recent change to the Material Change in Circumstance (MCC) provisions in the NER, we have considered the impact of changes in key underlying assumptions on what is considered optimal to procure, if our obligations change in the future, and identified re-opening triggers. This assessment may allow us to demonstrate that any future change in the preferred portfolio option due to the occurrence of these triggers is consistent with the RIT-T, in the event that a re-opening trigger occurs, without needing to redo the RIT-T assessment.

1.1 Purpose of this report

The purpose of this PADR is to:

- update the description of the identified need for this RIT-T, reflecting developments since the publication of the PSCR, including the publication of AEMO's 2023 System Strength Report;

[18] Specifically, Transgrid's obligation to meet the standard under Schedule 5.1.14 from 2 December 2025 is framed around the 'system strength standard specification' (which defines the binding requirement as the forecast requirements determined three years prior).

- summarise points raised in submissions to the PSCR and highlight how these have been addressed in the RIT-T analysis;
- describe the options being assessed under this RIT-T, including the options put forward by non-network proponents and how these have been combined (together with potential network investment components) into credible 'portfolio options';
- set out the basis on which the costs have been estimated at this stage of the RIT-T process;
- identify and confirm the market benefits expected from meeting the system strength requirements. This includes discussion of how benefits from changes in emissions have been quantified;
- present the results of the net present value (NPV) analysis for each of the options assessed;
- describe the key drivers of the NPV results, as well as the assessment that has been undertaken to ensure the robustness of the conclusion (including detailed sensitivity testing);
- provide details of the overall proposed preferred option at this stage of the process to meet the identified need; and
- set out the proposed re-opening triggers, building on the sensitivity assessments undertaken, to provide transparency to stakeholders on what may constitute a later material change in circumstance for this RIT-T.

Overall, this report provides transparency into the planning considerations for investment options to ensure Transgrid meets its obligations as the SSSP for NSW.

1.2 Submissions and next steps

The purpose of this PADR is to set out the reasons Transgrid proposes that action be taken, present the options that address the identified need, summarise how these options have been assessed (as well as the results of this assessment), and allow interested parties to make submissions and provide input to the RIT-T assessment.

Transgrid welcomes written submissions on materials contained in this PADR, including on the proposed re-opening triggers.

Submissions are due on 2 August 2024.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[19] In the subject field, please reference 'Meeting system strength requirements in NSW RIT-T PADR'.

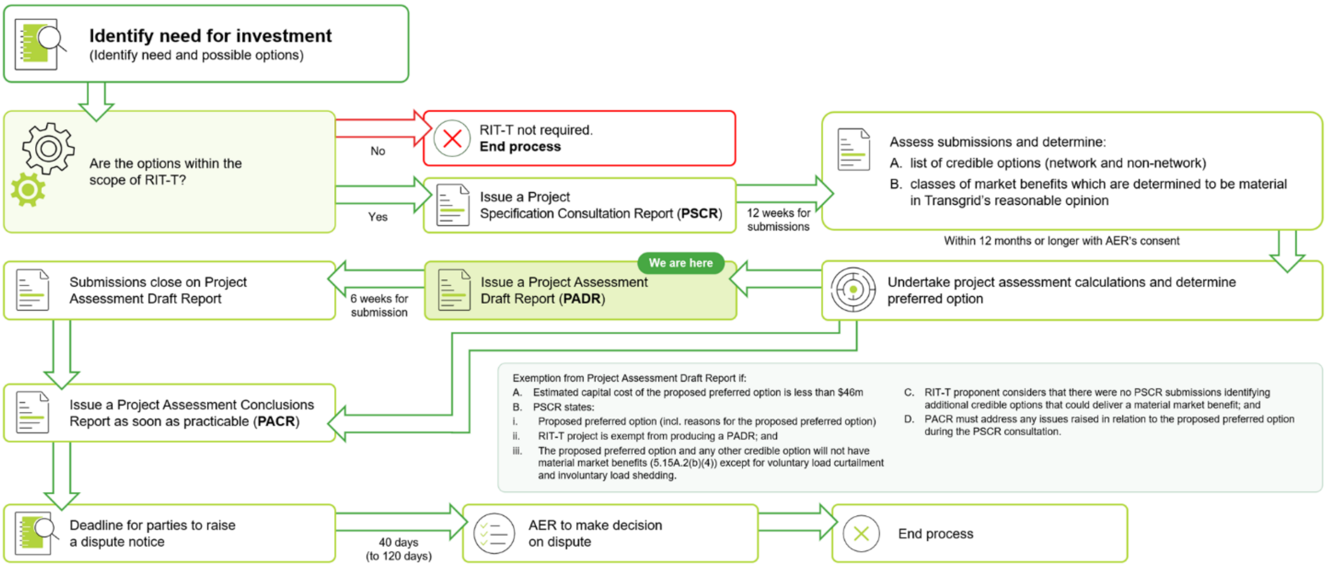
At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the publication of a Project Assessment Conclusions Report (PACR). The PACR will address all submissions received, including any issues raised in relation to the proposed preferred option. We anticipate publication of a PACR in Q1 of 2025, in order in order to meet NSW's

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

system strength requirements from 1 July 2025 (Shortfall requirement) and from 2 December 2025 (full system strength requirements).

Figure 1.1 – This PADR is the second stage of the RIT-T process



2 The identified need

System strength is a fundamental service required for the power system to operate in a secure state. In a network without adequate system strength there are inherent stability issues. Generators may be unable to remain connected during disturbances on the power system, control of the system voltage becomes more difficult, and protection systems that ensure safe operation of the network may not operate correctly. Insufficient system strength raises the risk of system instability and supply interruptions to end consumers.

As the SSSP for NSW we are required to undertake this RIT-T to make sufficient system strength available, as specified by AEMO, under the NER (clauses 11.143.15 and S5.1.14).

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the detail regarding the amount of system strength required, and the supporting assumptions, have been refined. The Draft 2024 ISP process resulted in changes to the AEMO IBR forecasts included in AEMO's 2023 System Strength Report, published in December 2023. For example, since the publication of AEMO's 2022 System Strength Report:

- the expected commencement date for Snowy 2.0, EnergyCo's expected timing for the delivery of the NSW REZs and coal retirement dates have been revised;
- EnergyCo has formally advised us that it plans to 'self-remediate' system strength for the Central West Orana (CWO) REZ stage 1, via ACEREZ, the appointed REZ Network Operator; and
- the Draft 2024 ISP has been published and reflects updated State and Commonwealth policies, including the Federal government targeting 82% renewable energy in our electricity grids by 2030.

These developments have a material impact on the amount of system strength Transgrid has to procure. Therefore, the analysis in this report uses the IBR forecast set out in AEMO's latest 2023 System Strength Report, published in December 2023, which reflects these developments.

This RIT-T is a 'reliability corrective action', as the options considered are for the purpose of meeting externally imposed regulatory obligations and service standards.

We are required to consider the market benefits that might arise under alternative options, as well as their costs. Given the options assessed are expected to affect the wholesale market compared to the 'do nothing' base case, we expect there to be significant market benefits from each of the options.

System strength is a fundamental service required for the power system to operate in a secure state. A power system with inadequate system strength raises the risk of system instability and supply interruptions to end consumers. As the SSSP for NSW, we are required to make sufficient system strength available, as specified by AEMO, under NER:

- Clause 11.143.15 to address the system strength Shortfall declared by AEMO from 1 July 2025 to 1 December 2025 at Newcastle and Sydney West, and
- Clause S5.1.14 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 into the future.

As outlined in the PSCR, we consider this a 'reliability corrective action' as the considered options are for the purpose of meeting externally imposed regulatory obligations and service standards, i.e., Clauses 11.143.15 and S5.1.14 of the NER.

This section outlines two key developments since the PSCR that have changed the assumptions underpinning the amount of system strength Transgrid is seeking to procure, in line with AEMO's most recent (2023) System Strength Report. It then outlines how these updated key assumptions have translated into changes in the expected amount of system strength services Transgrid needs to procure since the PSCR.

Transgrid notes that on the 22 May 2024, the NSW Government and Origin Energy agreed to extend the life of the Eraring Power Station by two years, to 30 June 2027. Transgrid expects that AEMO will reassess and update its Shortfall declaration following this, with its implications feeding into Transgrid's assessment for the system strength PACR (assuming it is released prior to the commencement of market modelling for the PACR). This, and other material changes since AEMO's 2023 System Strength Report will be considered as part of the PACR modelling.

System strength – the heartbeat of the power system

Under the umbrella of 'power system security', system strength can be likened to the heartbeat of the power system, necessary to maintain the secure operating envelope of the grid and enable the flow of electricity around NSW.

System strength can broadly be described as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.[20] A power system with inadequate system strength raises the risk of system instability and supply interruptions to end consumers. In a system with low system strength:

- generators may be unable to remain connected during disturbances on the power system;
- control of the system voltage becomes more difficult; and
- protection systems that ensure safe operation of the network may not operate correctly.

Synchronous coal generators are currently the largest contributor to the heartbeat of the power system, with system strength provided as a free byproduct of their production of electricity.

Inverter-based renewable generators, which typically have grid-following current source inverters as their grid interface, require a strong voltage waveform (or heartbeat) to generate power and remain connected following a power system disturbance.

As coal generation retires and renewables connect, Transgrid must proactively add new sources of system strength to the power system, to ensure its safe and secure ongoing operation.

Transgrid's obligations

Clause S5.1.14 of the NER requires that a Transmission Network Service Provider who is a SSSP use reasonable endeavours to plan, design, maintain and operate its transmission network, or make system strength services available to AEMO, to meet the following requirements at system strength nodes on its transmission network in each relevant year:

- maintain the minimum three phase fault level specified by AEMO at the system strength nodes; and
- achieve stable voltage waveforms for the level and type of IBRs and market network service facilities projected by AEMO in steady state conditions and following any credible contingency or protected event.

[20] AEMO, *System Strength Explained*, March 2020 – available at: https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf

Minimum three phase fault level

To ensure that protection systems operate correctly and voltages stay within acceptable levels, a minimum amount of system strength is required. Three phase fault levels are used to define minimum system strength requirements, measured in $MVA_{fault\ level}$ at the system strength nodes in NSW.

Stable voltage waveforms

SSSPs must use reasonable endeavours to ensure 'stable voltage waveforms', such that in steady state conditions IBRs and market network service facilities do not create, amplify or reflect instabilities. Avoiding voltage waveform instability following any credible contingency event or protected event should not depend on any of the inverter-based resources or market network service facilities disconnecting from the power system. Additionally, there should be no significant variation in the active or reactive power transfer at the connection point, except in accordance with applicable performance standards.

Importantly, stable voltage waveform support is not assessed at the system strength nodes, but rather at the points of connections of future IBRs.

Four criteria comprise AEMO's description of a stable voltage waveform. Criterion 1 and Criterion 2 focus on Root Mean Square (RMS) voltage magnitude and change in RMS voltage phase angle, which are fundamental indicators of voltage waveform stability in a power system. Criterion 3 focuses on the description of instantaneous three-phase voltage waveforms and Criterion 4 describes the threshold for undamped RMS voltage oscillations in the power system.[21]

These stable voltage waveform criteria are designed to facilitate a shift away from considering voltage waveform stability largely as an outcome of fault level contribution. That being said, while detailed electromagnetic transient (EMT) analysis is recommended for study horizons in the 1-to-2-year range, AEMO suggests that steady-state RMS analysis is more appropriate for longer-term planning studies. [22]

Analysis for this PADR uses steady-state RMS analysis (Available Fault Level methodology) as a proxy for stable voltage waveforms, aligning to AEMO's recommendation that steady-state RMS analysis is more appropriate for long term investment decisions as considered under this RIT-T. Transgrid is actively pursuing a mixed RMS and EMT approach for the PACR analysis, where EMT will focus on the shorter-term deployments of grid-forming batteries for stable voltage waveform support.

2.1 Key assumptions underpinning the identified need have changed since the PSCR

The three sections below outline how the key assumptions regarding system strength have changed since the PSCR was published.

2.1.1 Our requirements are consistent with AEMO's 2023 System Strength Report

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the detail regarding the amount of system strength required has been refined. This has been driven by the Draft 2024 ISP process resulting in changes to the AEMO IBR forecasts included in the 2023 System Strength Report, published in December 2023 (which drives our obligation).

[21] AEMO, *System Strength Requirements Methodology*, December 2022 – available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/ssrmiag

[22] AEMO, *System Strength Requirements Methodology*, December 2022. AEMO states *"The use of electromagnetic transient (EMT) analysis is preferred for power system stability studies to identify system strength issues, such as control interactions between IBRs, in time horizons where network and generator models are precise (e.g. 1 to 2 years). However, EMT simulations are not fit-for purpose in long-term planning studies because their accuracy is limited by the use of generic models for conceptual projects."*

The analysis in this report uses the IBR forecast set out in AEMO's latest 2023 System Strength Report (published in December 2023) and so differs from that presented in the PSCR, which was based on the previous 2022 System Strength Report.

The latest AEMO System Strength Report reflects a number of key developments since the 2022 System Strength Report that have had a material impact on the amount of system strength that Transgrid has to procure, including:

- changes to NSW REZ dates (which align with the latest information from EnergyCo on the timing for each);[23]
- a delay to the assumed commissioning date for Snowy 2.0 (consistent with the Federal Government's latest view regarding its timing);[24]
- the inclusion of latest State and Commonwealth policies, in particular the Federal government targeting 82% renewable energy in our electricity grids by 2030; and
- changes to coal retirement dates (to align with the Draft 2024 ISP).

While Transgrid understands that its system strength requirement for each year is locked in three years in advance (the three-year binding period), and after that does not change even if AEMO updates the forecast in a later System Strength Report, it has nevertheless updated the IBR forecast underpinning the system strength requirement in all years to align with the 2023 System Strength Report. This is explained further in the box below.

Transgrid is planning to AEMO's 2023 System Strength Report IBR forecasts for all years

Transgrid's obligation to meet the standard under NER S5.1.14 is framed around the 'system strength standard specification', which defines the binding requirement as the forecast requirements determined three years prior and, specifically, disregards any subsequent revisions under clause 5.20C.1I. In December 2022, AEMO published the 2022 System Strength Report, which forecasts IBR for a period of ten years, with a three-year binding period to 2 December 2026 (i.e. 2025/26 and half of 2026/27).

While under a strict interpretation of the NER it may not be possible to vary IBR forecasts within the three-year binding period, Transgrid believes that in specific circumstances it is prudent and efficient, and in the best interests of consumers, to make revisions to IBR forecasts within the three-year binding period (and so has done so as part of this PADR). Specifically, given the above discussed changes that have occurred since the 2022 System Strength Report, the 2023 System Strength Report now projects there to be the following for 2025/26 (the last full year, to provide an example):

- 102 MW *more* IBR at the Wellington node (2,210 MW compared to 2,108 MW);
- 162 MW *less* IBR at the Armidale node (515 MW compared to 677 MW);
- 56 MW *less* IBR at the Darlington Point node (665 MW compared to 721 MW).

If the latest AEMO IBR forecasts are not taken into account, Transgrid would not be planning to procure the right amount of system strength surrounding these nodes. This would (in a more extreme case) raise

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[23] EnergyCo, *NSW Network Infrastructure Strategy - Appendix B: Network Infrastructure Options*, May 2023, pp 4-17. The updated REZ dates are reflected in the IBR forecast published in the latest 2023 System Strength Report.

[24] In August 2023, the Federal Government Department of Climate Change, Energy, the Environment and Water announced a delay to the expected commercial commencement of operations at Snowy 2.0. Specifically, Snowy 2.0 is now expected to be commissioned in December 2028, which is two years later than was expected at the time of the 2022 System Strength Report (see: Snowy Hydro, *Securing the Future of Critical Energy Transformation Projects*, 31 August 2023, available at: https://www.snowyhydro.com.au/news/securing-the-future-of-critical-energy-transformation-resets/). This updated timing for Snowy 2.0 is reflected in the 2023 System Strength Report (see: AEMO, *2023 System Strength Report*, December 2023, p. 60).

the risk of unserved energy for end consumers and/or result in an inability to allow for the dispatch of low-cost renewable energy in the future.

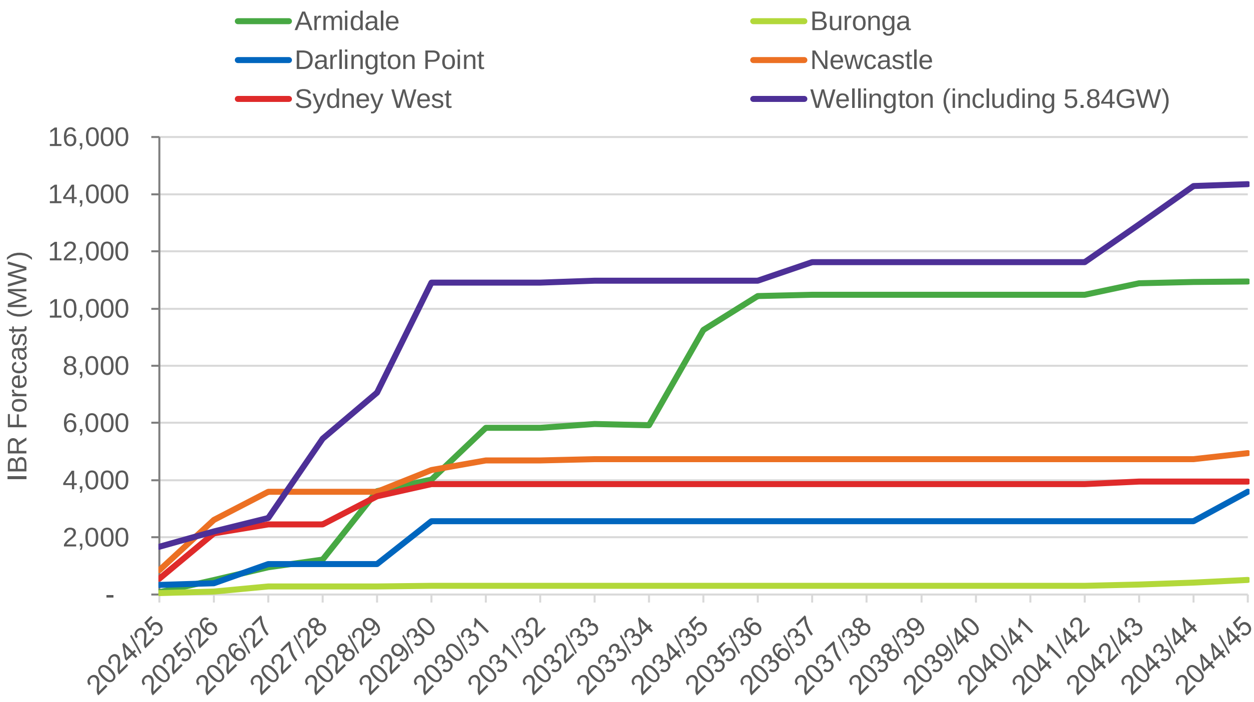
Given Transgrid believes there is sufficient time to contract with non-network solutions to meet the revised 2025/26 and part year 2026/27 IBR forecasts, it Transgrid is now planning the system strength remediation based on AEMO's IBR forecasts from the 2023 System Strength Report for all years. This will ensure that Transgrid's provision of system strength is driven by the most up-to-date, and best available IBR forecasts from AEMO.

Transgrid have informed the AER that this approach is a departure from the strict requirement regarding the binding three-year requirement and how it is expected to be in the interest of consumers.

Transgrid notes that our approach taken is consistent with the statement in the AEMO 2023 System Strength Report which notes that the near-term years of the IBR forecasts may require adjustment by the SSSP when preparing system strength services as more information becomes available.[25]

As a result of these changes, the efficient-level requirements within this PADR are driven by the IBR forecasts presented in Figure 2.1 below (which align with those in AEMO's 2023 System Strength Report).

Figure 2.1 – AEMO's IBR forecast for each system strength node, from the 2023 System Strength Report



While the AEMO IBR forecasts in the 2023 System Strength Report extend to 2034, we need forecasts of IBR expected to be commissioned in NSW out to 2045 in order to determine the efficient level of system strength for the modelling period in this PADR. Noting that IBR forecast within AEMO's System Strength Reports are driven by AEMO's ISP Step Change scenario, we have used data from the Draft 2024 ISP to extend the IBR forecast out to 2045.

In addition, as part of the new system strength requirements, the current 'do no harm' rules evolve into the System Strength Mitigation Requirement (SSMR) where new connecting parties may opt into a system strength charge rather than self-remediate. While these new rules only apply to projects that have

[25] AEMO, *2023 System Strength Report*, December 2023, p. 17.

submitted a Connection Application after 15 March 2023, projects that fall under the old rules may opt into the new SSMR and pay the system strength charge rather than having to self-remediate.[26]

While Transgrid is only obliged to procure enough system strength to support the renewables that plan on paying the system strength charge, the AEMO IBR forecasts include some projects that fall under the old 'do no harm' rules.

Transgrid has therefore assessed each specific project in AEMO's IBR forecast to see their progress in Transgrid's connection pipeline and, if a project is committed, existing or has submitted its Connection Application before 15 March 2023, the project sits under the old 'do no harm' rules. Transgrid's network connections team has advised that none of these projects (22 in total) plan on opting into the new rules and paying the system strength charge. We have therefore assumed that we do not have to procure system strength to support these renewables.

2.1.2 The 'self-remediation' of the CWO REZ stage 1 by the REZ Network Operator

In early 2023, EnergyCo informed Transgrid that it planned to 'self-remediate' system strength for Stage 1 of the CWO REZ (5.84 GW of IBRs) as part of its build, which will be implemented by 'ACEREZ'[27] (as the CWO REZ Network Operator), rather than by Transgrid as NSW's SSSP. This was also stated in the NSW Government's May 2023 Network Infrastructure Strategy[28], was formalised in a letter from EnergyCo to Transgrid on 24 October 2023 and ACEREZ has now signed the commitment deed as the Network Operator for CWO REZ Stage 1.

Transgrid are expecting regulations to be made by the NSW Government in 2024 that expressly override Transgrid's obligations under the NER in relation to the system strength for the CWO REZ, in light of the planned self-remediation.

ACEREZ and EnergyCo have advised us that seven 250 MVA_{rated} synchronous condensers are planned for the self-remediation of the CWO REZ, with each synchronous condenser providing 834-955 MVA fault current at their point of connection. The assessment in this PADR assumes that each unit provides 834 MVA fault current at their point of connection.[29] Transgrid have modelled the self-remediation of CWO REZ Stage 1 so that it has no net negative effect on system strength in the wider power system.

While the 5.84 GW of IBRs have been removed from Transgrid's obligations, Transgrid have included the 5.84 GW of IBRs within CWO REZ in the market modelling (as the energy market would otherwise be affected) and included the CWO system strength remediation as a modelled project (locking it into the base case and option cases), to ensure we capture the interplay of fault current provision that flows from the REZ to the NSW backbone. See further discussion in the separate Baringa modelling report released alongside this PADR.

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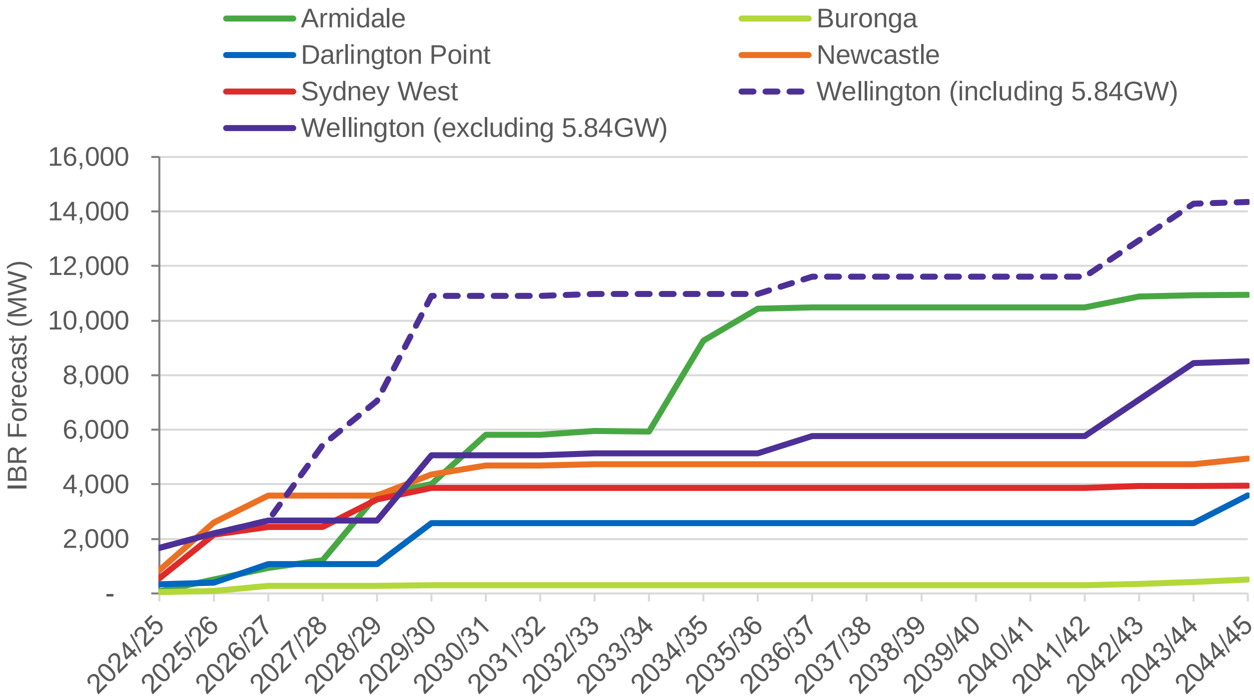
[26] AEMC, *National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021*, Final Determination, 21 October 2021, p. ix.

[27] As at the date of this draft, while the NSW government has entered into a commitment deed with ACEREZ – a consortium comprised of ACCIONA, COBRA and Endeavour Energy – as preferred network operator for the REZ, this has not yet been finalised (but is expected for the second half of 2024). See: https://www.nsw.gov.au/media-releases/orana-rez-powering-ahead

[28] System strength remediation for phase 1 of the CWO REZ (5.84 GW IBR capacity) is "included as part of the network build", which will be implemented by the REZ Network Operator. See: EnergyCo, *NSW Network Infrastructure Strategy - Appendix B: Network Infrastructure Options*, May 2023, p 4.

[29] EnergyCo will advise Transgrid when a final fault current provision has been selected, and Transgrid will consider whether this assumption needs to be updated for the PACR.

Figure 2.2 – AEMO's IBR forecast for each system strength node, with IBR obligations for Wellington displayed with and without 5.84 GW of IBRs from CWO REZ stage 1



While EnergyCo has indicated that other REZs may follow a similar self-remediation process for system strength (undertaken by a REZ network operator), Transgrid understands that no decision has been made for other REZs. As such, without sufficient certainty of whether system strength will be delivered by a future REZ Network Operator (e.g. for New England REZ or stage 2 of CWO REZ), we are currently assuming in our core modelling that all additional IBRs will be remediated by Transgrid (except for 5.84 GW of IBRs in stage 1 of CWO REZ). This assumption will be reassessed during the PACR preparation, as appropriate, based on EnergyCo's advice at that time.

To assess the implications of system strength self-remediation which could occur in a REZ by a third-party network operator, we have undertaken a sensitivity where IBRs within stage 2 of CWO REZ and the New England REZ are removed from Transgrid's network need (see section 9.7.1).

2.1.3 Extension of Eraring Power Station

We note that on the 22 May 2024, the NSW Government and Origin Energy agreed to extend the life of the Eraring Power Station by two years, to 30 June 2027. We expect that AEMO will reassess and update its Shortfall declaration following this, with its implications feeding into Transgrid's assessment for the system strength PACR (assuming it is released prior to the commencement of market modelling for the PACR). An updated Shortfall declaration, as well as implications of Eraring's extension on our optimal portfolio of solutions will be progressed as part of the PACR modelling.

A full co-optimisation with inertia requirements has not been undertaken for this PADR

In May 2023, the AEMC announced that it would no longer pursue the operational security mechanism approach to schedule and dispatch network services (including system strength) as part of what was then called the 'operational security mechanism' (OSM) rule change. The AEMC considered that there were simpler and more immediate solutions available to address the problem compared with an OSM and committed to consulting on alternative arrangements via a new directions paper.[30]

In March 2024, the AEMC released its final determination for the rule change (now renamed as the 'improving security frameworks for the energy transition' rule change). The final determination aligns the new system strength rules with the inertia requirements so that in the future TNSPs can co-optimise system strength requirements with inertia requirements.[31] Transgrid is supportive of these changes.

From 1 December 2024, AEMO will set a ten-year forward requirement for the minimum system-wide inertia level, being the minimum amount of inertia required for the mainland states for continuous operation of the power system in a secure operating state. AEMO will also forecast the proportion of inertia allocated to each sub-network ('inertia sub-network allocation'), the 'satisfactory inertia level' and 'secure inertia level' for each sub-network, and the 'sub-network islanding risk'. A binding three-year inertia requirement will occur, and Transgrid needs to procure sufficient inertia from 1 December 2027 onwards to meet these requirements.[32]

However, under the timeline for AEMO to set the inertia requirements, we will not know the NSW-specific inertia requirements (based on a mainland-wide minimum level) until 1 December 2024, making co-optimisation difficult. We note that we will receive additional inertia support through the addition of flywheels required to support stable voltage waveform, as outlined below.

Inertia is required for stable voltage waveform support

A core component of stable voltage waveform support is the ability to adequately damp voltage oscillations. Transgrid's detailed network planning studies have concluded that inertia is integral to adequately damp voltage oscillations, and therefore is integral to providing stable voltage waveform support. As such, studies optimising the inertia of synchronous condenser quantities for stable voltage waveform support were performed – these studies identified an optimum inertia value of 1500MWs is required from each synchronous condenser. We understand that most, but possibly not all synchronous condensers will need a flywheel to achieve 1500 MWs, with flywheels adding only a 10% increase in costs.

Transgrid's preliminary power system modelling suggests that high inertia synchronous condensers, necessary for stable voltage waveform support, will have a material flow on benefit to help enable Transgrid to meet its meet future inertia obligations.

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30 AEMC, *Operational security mechanism – Update on the direction for the Operational Security Mechanism rule change*, 25 May 2023.

31 AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024*, Final Determination, 28 March 2024, p iv, para 20.

32 AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition)*, Rule 2024 No. 9, 28 March 2024, clauses 5.20B.2(a), (b), (e)-(f) & (g)-(h).

3 Consultation on the PSCR and responses to the EOI

The PSCR for this RIT-T was published in December 2022, along with an EOI that provided additional detail on the technical requirements that non-network options would need to meet to provide system strength services to Transgrid, and to specifically seek submissions from proponents of these options. Submissions to both the PSCR and EOI were requested by 30 March 2023.

On 1 February 2023, Transgrid held an industry briefing on the EOI, attended by over 200 people.

We received a substantial number of responses to the EOI covering over 60 individual solutions as well as four formal submissions to the PSCR on issues to be considered in the RIT-T assessment.

3.1 Responses to the EOI

The EOI process resulted in non-network option submissions from 25 parties, covering over 60 individual potential technology solutions, including:

- over 10 GW of existing or conversions of existing synchronous generators;
- over 5 GW of other new generation and energy storage projects, including pumped hydro and gas; and
- a pipeline of more than 10 GW of innovative grid-forming batteries.

Based on the capacity (MW) of proposed solutions, and excluding synchronous generator modifications, proposed solutions can be broken down into:

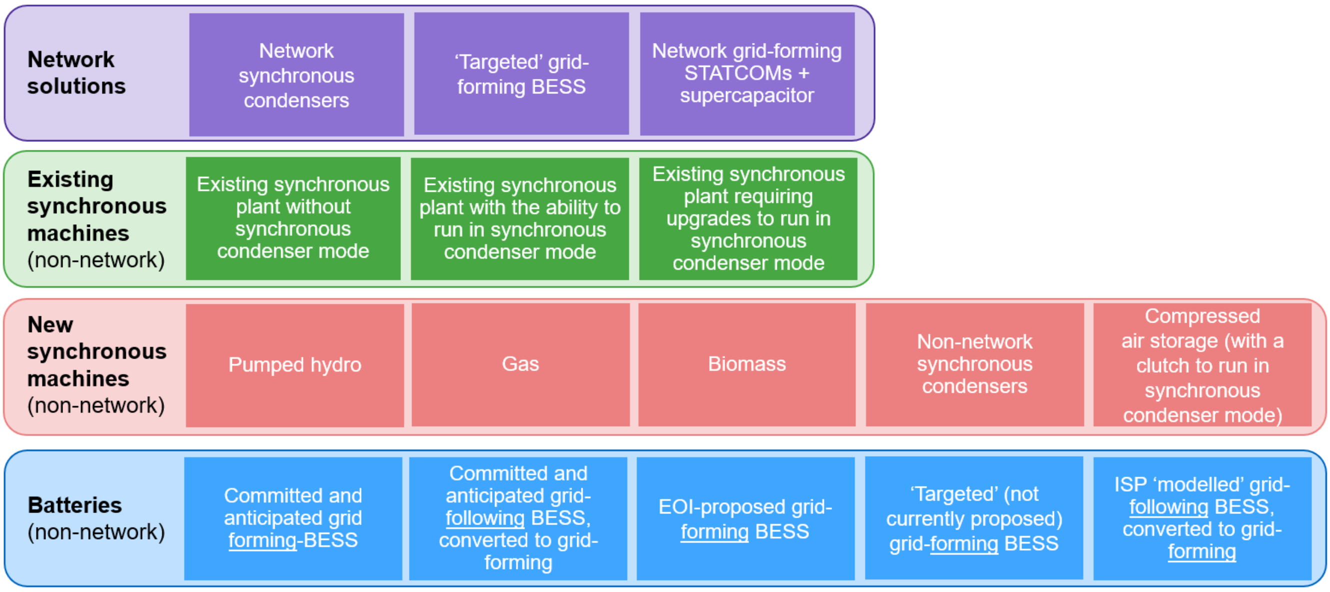
- 39% grid-forming BESS, 30% hydro, 21% coal, 10% gas and biomass; and
- 44% proposed, 38% existing and 18% committed/anticipated.

In addition, based on the number of solutions available for each period, proposals can be summarised as:

- 43% available to assist with the Shortfall in system strength at Sydney West and Newcastle from 1 July 2025 to 1 December 2025;
- In addition to the 43% above which can continue to support beyond 1 December 2025, the remaining 57% being able to assist with meeting the minimum and efficient levels of system strength from 2 December 2025 onwards, as follows:
  - 21% from 2 December 2025/26, 10% in 2026/27, 14% in 2027/28, 5% in 2028/29, and 7% in 2029/30.

While most proposed solutions would be provided as a non-network solution (where Transgrid would contract with the provider for the provision of system strength), Transgrid also developed 40 network solutions (where Transgrid would own and operate the asset), e.g., the solutions shown in purple below. Figure 3.1 summarises the broad types of solutions considered in this PADR.

Figure 3.1 – Summary of the types of solutions considered within this PADR



Over the course of preparing this PADR, we have had numerous discussions with proponents of solutions. Overall, the analysis presented in this PADR has been strongly informed by this consultation, which has helped ensure the robustness of the analysis. We thank all parties for their valuable input to the consultation process to date.

Section 4 outlines how the solutions proposed in submissions to the EOI have been considered and included as part of the PADR assessment.

3.2 Submissions to the PSCR

In addition to the responses to the EOI, we received submissions from five parties directly in response to the PSCR, four of which have been published on our website (one requested confidentiality).[33] The four parties who did not request confidentiality are:

- Energy Australia;
- Origin Energy;
- Smart Wires; and
- Tesla.

There were ten broad areas that were raised across these submissions:

- further specification of the identified need;
- the scope of the network components;
- option value and the timing of options;
- AEMO directions and involuntary load shedding under the base case;

[33] https://www.transgrid.com.au/projects-innovation/meeting-system-strength-requirements-in-nsw

- treatment of non-network option costs;
- how inter-regional assets are assessed;
- transparency regarding the modelling;
- how the broader ongoing work program on system services will affect this RIT-T (and vice versa);
- location of new system strength resources; and
- the use of modular power flow control (MPFC) technology

The key matters raised in non-confidential submissions are summarised and responded to in Appendix E.

4 Options have been developed through a portfolio optimisation approach

Transgrid has adopted a 'portfolio optimisation' approach to form credible options for this RIT-T. This approach is a practical way of assessing and grouping the large number of individual solutions proposed in response to the EOI and PSCR, plus additional network solutions. It also recognises that no one solution can address the requirements in isolation.

Transgrid has developed a robust power system and market modelling methodology to enable the identification of the optimal portfolio of solutions to meet the system strength requirements. Transgrid's methodology integrates system strength constraints into market modelling software (PLEXOS) and uses its Long-Term capacity expansion capabilities to optimise and trade-off the deployment of new build options that provide system strength, with a change in the operating patterns for existing synchronous machines. The process finds the optimal 'portfolio of solutions which maximise net market benefits while meeting system strength requirements. It does this in a similar way to what AEMO does in its ISP, to identify the optimal timing and mix of generation assets, storage and transmission.

Transgrid validated the output of PLEXOS' portfolio optimisation by analysing the results within PSS®E, with a full network topology including geographically dispersed IBR locations. This process meant tens of thousands of power system modelling simulations occurred in order to validate the portfolios of solutions.

The portfolios have been designed to meet energy demand and system strength requirements at lowest total system cost (i.e. maximum net market benefits), with different portfolios reflecting different constraints, reflecting key influences on the expected optimal solution.

The number of proposals received meant that billions of potential solution combinations had to be considered and co-optimised across the six system strength nodes in NSW, as well as the many points of connections for future IBRs. This, combined with the fact that system strength contributions are dynamic and non-linear and that individual contributions depend on which other units are operating at the same time, necessitated the development of a portfolio optimisation process for considering and forming 'portfolio options'.

Transgrid engaged Baringa Partners ('Baringa') to develop and apply this portfolio optimisation approach as well as to assess the net market benefits expected to arise under each of the portfolio options (which are discussed in section 7.2).

This section outlines the key features of the portfolio optimisation approach applied to develop portfolios of existing and emerging non-network and network solutions that best meet the needs of the NSW power system and energy consumers throughout the energy transition. Baringa's market modelling report includes additional detail on key elements of this approach, along with more detail regarding how the wholesale market modelling has been undertaken.

4.1 Assumed technical feasibility

Transgrid have assumed that all solutions are technically feasible[34] to determine whether the solutions are likely to form part of the overall preferred portfolio option. Following the publication of this document,

[34] The one exception to this is for the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West where we have only assumed it is technically feasible for one portfolio option ('portfolio option 3'), as outlined in section 5 below.

Transgrid will commence a more detailed assessment of the technical and commercial feasibility of solutions that could form part of the preferred portfolio option in the final PACR assessment.

4.1.1 Technical feasibility of grid-forming batteries

Grid-forming batteries hold significant potential to co-optimise system strength provision with other market benefits. Equally, grid-forming batteries and grid-forming inverter technologies are relatively novel and have not yet been deployed at significant scale. Comprehensive power system and protection studies need to be undertaken to confirm the effectiveness of grid-forming battery technology to provide system strength support.

In May 2024, AEMO published its Update to the 2023 Electricity Statement of Opportunities, including an assessment of the projected system security outlook for the NEM. It identified system strength as likely to be the most onerous emerging system security requirement in all regions, and called out that *"approximately 22 equivalent synchronous condensers [NEM-wide] are needed to meet minimum fault level requirements and must be delivered by devices that can provide protection-quality levels of fault current – such as new synchronous condensers, service contracts with existing hydro or thermal units, or through the retrofit of those existing units themselves."* [35] This position therefore precludes minimum fault current requirements being met by grid-forming batteries.

Transgrid engaged Aurecon to undertake an independent assessment of the maturity of grid-forming BESS for system strength support. The box below summarises Aurecon's assessment.

Aurecon's assessment of the maturity of grid-forming BESS for system strength

Transgrid engaged Aurecon to undertake an independent assessment of the maturity of grid-forming BESS to provide fault current to meet minimum fault level requirements and to provide stable voltage waveform support to enable the secure operation of new renewables.

Aurecon concluded that:

- there is insufficient evidence (either at-scale deployments or in modelling) to rely on grid-forming BESS to support minimum fault level requirements (until 2032/33), in particular because:
    - the ability for grid-forming BESS to provide a satisfactory fault current response to enable the safe (and successful) operation of protection equipment in the transmission network has not been confirmed; and
    - the performance and stability of grid-forming BESS at their rated current limits, when fault current injection is critical, is not yet established, nor has the stability of these BESS been confirmed for strong areas of the grid.[36]
- grid-forming BESS are sufficiently mature for stable voltage waveform support, up to a maximum of 50% of the efficient level solution size. This limit aims at striking a balance between a sizeable deployment of grid-forming batteries, minimising the risk of unknowns, and avoiding the frequent curtailment of grid-following inverter-based resources in practice.

The Aurecon report has been released alongside this PADR. An additional source of relevant information on the topic of grid-forming batteries and protection system operation was recently published [Sandia National Laboratories](#).

[35] AEMO, *Update to the 2023 Electricity Statement of Opportunities*, May 2024, p. 43.

[36] Grid-following inverters face stability challenges in weak areas of the grid, and conversely, grid-forming inverters face stability challenges in strong areas of the grid.

For Transgrid's PADR market modelling, grid-forming batteries have been excluded from contributing to the minimum fault level requirements until 2032/33. However, Transgrid has not explicitly applied Aurecon's recommended 50% limit for the efficient level within the PADR modelling, because breaches to this limit are observed when there are no other alternative solutions available to meet the efficient level need (i.e., prior to when synchronous condensers are assumed to be able to be delivered). In addition, Transgrid observed this limit being breached in regions that have low efficient level requirements, but high minimum level requirements, for example surrounding Newcastle and Sydney West. There may be a case for this situation to be acceptable. Transgrid plans to further refine this assessment within the PACR market modelling.

The contribution of grid-forming batteries for stable voltage waveform support

Transgrid understands that grid-forming batteries are typically limited in their current overload capabilities (usually 1 to 2.0 per unit overload current), and as such they do not compare as favourably as synchronous machines (which can provide 5 to 6 per unit overload fault current) for fault current.

However, Transgrid recognises that fault current is not the measure for the provision of stable voltage waveform support. Power system studies undertaken by Transgrid and others in the industry indicate that grid-forming batteries can provide more stable voltage waveform support than their overload capability suggests, if configured and tuned to directly support the criteria for stable voltage waveform (e.g. via fast dynamic voltage control).

Market modelling for the PADR uses fault current as the proxy for stable voltage waveform support, via the Available Fault Level (AFL) calculation methodology as specified by AEMO in its System Strength Impact Assessment Guidelines (v2.1, 2023). AFL is used as a proxy to quantify the indicative impact of IBR on the power system, and is suggested by AEMO as an appropriate method for approximating system strength requirements in future years for which accurate EMT modelling is not possible.

To account for the disadvantage that grid-forming BESS face when stable voltage waveform support is 'valued' using its fault current provision, Transgrid has introduced a 'boost factor' concept into the PADR modelling. To calculate the equivalent stable voltage waveform support, the fault current contribution of grid-forming batteries (currently assumed at 1 per unit or rated capacity at point of connection for all batteries) is boosted by 3.1 times, in effect tripling its effectiveness (when assessed on a fault current basis). This is derived from Transgrid's power system modelling assessment, which is being continued and refined for the PACR market modelling.

A more detailed explanation of the approach to this 'boost factor', and other key assumptions applied to grid-forming BESS, can be found in Baringa's PADR market modelling report.

4.1.2 Confirming the technical feasibility of grid-forming batteries

The PADR results demonstrate that 4.8 GW of grid-forming batteries form part of the optimal portfolio of solutions. Yet as stated above, for the purposes of the PADR, all solutions are assumed technically feasible in order to determine whether they are likely to form part of the overall preferred portfolio option or not.

At the start of the PADR consultation period, Transgrid will be requesting PSCAD models from grid-forming battery proponents, to assess and confirm the technical feasibility of each proposed grid-forming battery project. This assessment will validate plant performance against Transgrid's technical requirements, and will be required before the plant can be considered part of the optimal portfolio of solutions at the final PACR stage.

A portfolio of 4.8 GW of grid-forming batteries supporting stable voltage waveform will provide Transgrid with a measured and safe approach to test and build confidence in the capabilities of grid-forming batteries for fault current support, necessary before Transgrid will consider this technology suitable for meeting minimum fault level requirements.

4.2 Range of solutions assessed in the portfolio formation process

The 'portfolio formation' process has assessed a wide range of potential solutions, including:

- existing plant that provide system strength as part of typical market dispatch (i.e., where they do not change their behaviour),
- existing plant that would need to be 're-dispatched' to provide system strength; [37] and
- new sources of system strength capacity (including new generating assets, grid-forming BESS, synchronous condensers and grid-forming STATCOMs with a supercapacitor).

Assets that are new sources of system strength include projects that are already under development (some of which have already achieved "anticipated" or "committed" status) as well as projects that have been proposed primarily or solely to meet a system strength need.

These new sources of system strength may have been proposed by proponents through Transgrid's EOI process, or have been included by Transgrid as a new solution 'targeted' to the best location for system strength. A proponent of these new 'targeted' solutions may be Transgrid or a non-network proponent.

Figure 4.1 provides a conceptual representation of how system strength provision and the type of solutions under each portfolio change over time. Each portfolio effectively differs in terms of how new system strength capacity is added and how existing synchronous machines are re-dispatched (i.e., the purple and green portions of the figure).

Figure 4.1 – Conceptual representation of system strength provision under each portfolio of solutions

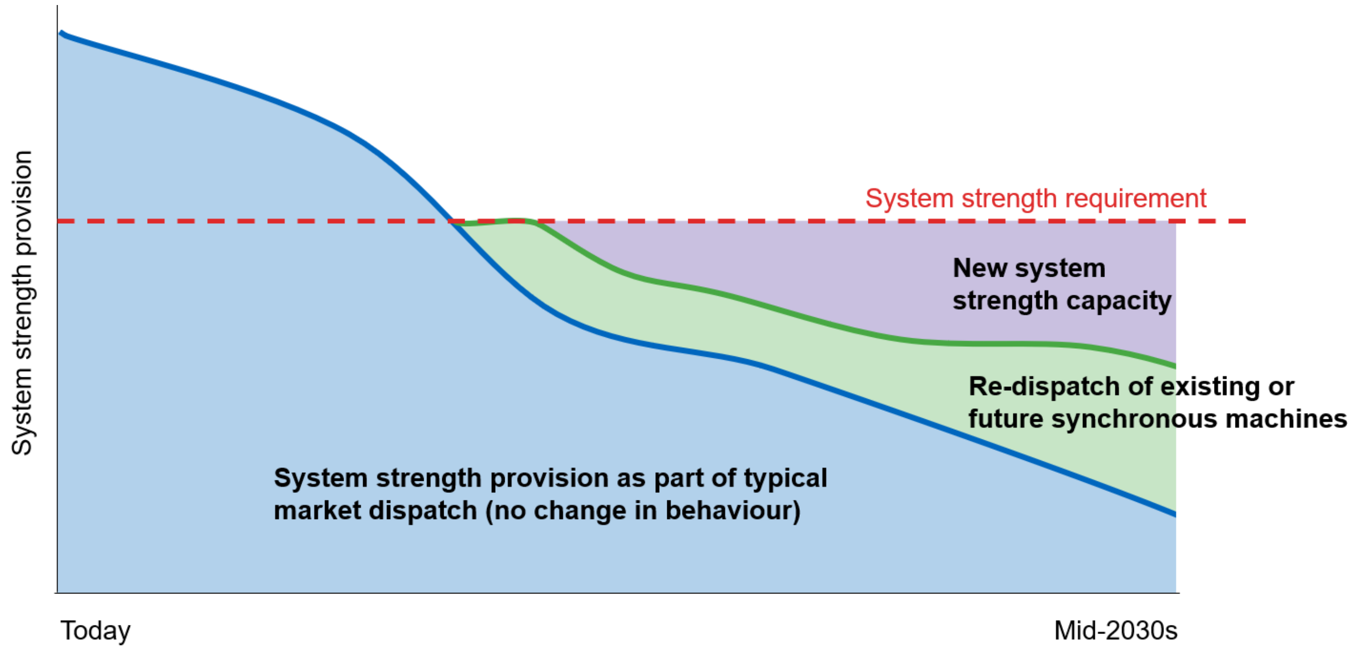


Figure 4.2 below summarises the 11 broad types of proposed solutions that have been assessed in the portfolio formation process (outlined in section 4.3), as well as key assumptions about how they have been

[37] The word 're-dispatched' or 're-dispatching' has been used to represent system strength solutions (typically existing or future synchronous generators) which are 'enabled' or 'scheduled-on' by AEMO for the purpose of providing system strength services.

assessed. Solutions comprise of non-network solution (where Transgrid contracts with the provider for the provision of system strength) and network solutions (where Transgrid will own and operate).

Figure 4.2 – Summary of individual system strength solutions available (and key assumptions regarding each)

Existing synchronous plant without synchronous condenser mode	• Provision of system strength when operating as part of normal market dispatch (i.e., units must be running at or above their minimum stable level) • This category includes coal and gas generators, as well as some hydro units
Existing synchronous plant with the ability to run in synchronous condenser mode	• Existing hydro plants that already have the ability to switch between operating as part of normal market dispatch (and generate electricity) or operate in synchronous condenser mode (without generating electricity)
Existing synchronous plant which require upgrades to run in synchronous mode	• Existing gas and hydro plants with the option to make capital investment to enable operation in synchronous condenser mode
Committed and anticipated grid-forming BESS	Assumed as part of the base case and all option cases: • Some have grid-forming capability • Those with grid-following capability have the option to make investment in grid-forming capability
EOI-proposed grid-forming BESS	• Specific proposals proposed by proponents in response to our system strength EOI • Not considered committed or anticipated under the RIT-T at this stage and so their full cost is included if selected for an portfolio option
ISP 'modelled' grid-following BESS, converted to grid-forming	• Future BESS which are part of AEMO's Integrated System Plan Step Change scenario are assumed to be in the base case and all option cases • All are assumed to be grid-following, which have the option to pay to upgrade to grid-forming
'Targeted' grid-forming BESS	• Proposed by Transgrid as a network solution, but could be built as a non-network solution if a proponent comes forward
Grid-forming STATCOMs + supercapacitor	• Grid-forming STATCOMs coupled with a supercapacitor (which acts like a grid-forming battery with a very short duration of storage) • Represented as a load in market modelling, with the size of the load set by losses • No additional benefits outside of system strength, inertia and voltage support
Network synchronous condensers	• Represented as load in market modelling, with the size of load set by losses • No additional benefits outside of system strength, inertia and voltage support • Each synchronous condenser provides 1,150MVA fault level contribution at its point of connection to the transmission network
Non-network synchronous condensers	• Represented as load in market modelling, with the size of load set by losses • No additional benefits outside of system strength, inertia and voltage suport
New build gas, pumped hydro, compressed air storage and biomass plant	• Capable of providing system strength when running at or above minimum stable generation level (for gas and biomass) • Capable of providing system strength when generating and pumping or when running in synchronous condenser mode (if functionality exists) for pumped hydro and compressed air storage

All solutions assessed in the portfolio optimisation process are assumed to have proponents for the purposes of this PADR, to identify whether they are likely to form part of the overall preferred portfolio option or not. While many explicitly do have proponents, others are either unclear regarding whether they have a formal proponent or reflect more ‘generic’ solutions (and it is these solutions that have been assumed to have proponents for the PADR assessment).

Transgrid welcome proponents of non-network solutions come forward with additional solutions that could form part of the optimised portfolio of solutions.

In addition, as part of the PACR, Transgrid intend to investigate further the impact on the expected overall net benefit of variations to the portfolios that would reduce the network support costs customers would face, whilst continuing to provide sufficient system strength.

Transgrid have assumed that developers of the ‘modelled’ batteries in AEMO’s IBR forecast would, acting reasonably, be willing to upgrade their batteries from grid-following to grid-forming, if Transgrid offered a network support agreement that covers the incremental cost of doing so.[38]

4.3 Portfolio optimisation process for forming credible options

Transgrid engaged Baringa to develop and undertake the portfolio formation process – the key aspects of which are summarised in the subsections below. For more detail on the approach to forming portfolios for this PADR, please refer to Baringa’s market modelling report.

A Baringa constructed PLEXOS Long-Term model was used to form optimal system strength solution portfolios. Mixed-integer programming techniques were used to compute a least cost, whole-of-NEM solution that progressively solves both the capacity expansion & unit commitment problems with respect to Transgrid’s system strength obligations. It does so through a tiered, interrelated modelling methodology which forms, refines and ranks a preferred set of system strength solutions.

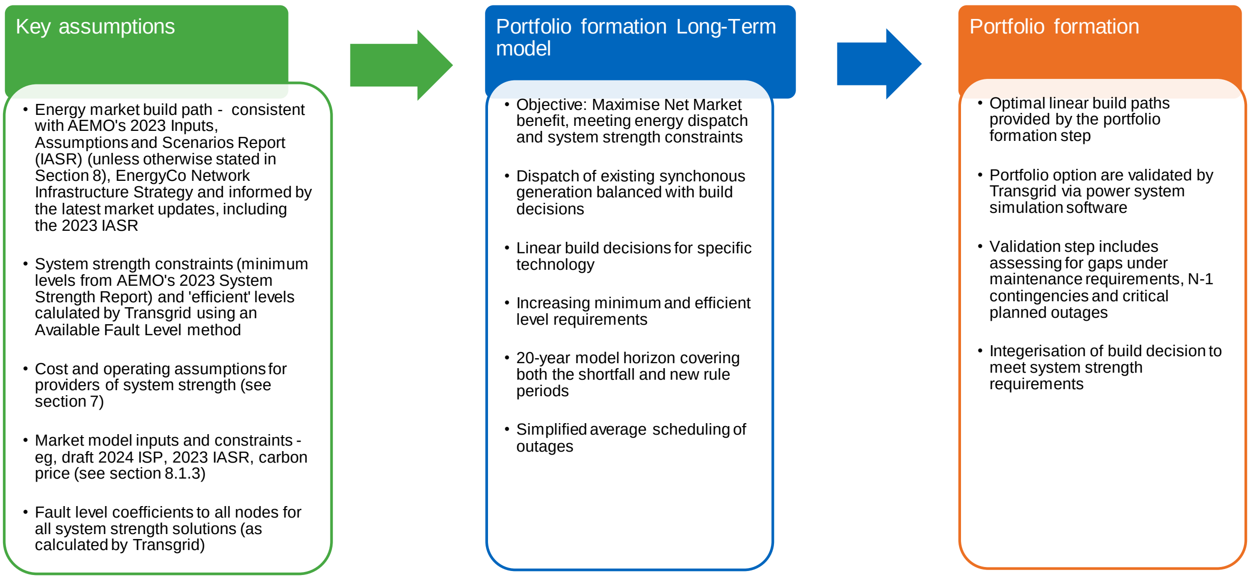
In this portfolio formation process, Transgrid considered more than 100 potential non-network and network solutions, leading to more than 2^{100} possible combinations. The combination of these solutions that maximises net economic benefits was determined for four cases (“portfolio options”), and the net economic benefits assessed against a base case (‘counterfactual’).

4.3.1 Approach to forming portfolio options

Each portfolio option is formed to maximise net economic benefits based on the specific assumptions made in that option. These assumptions include the changing of deployment timelines for technology options, varying the assumed technical feasibility of projects providing system strength (i.e. the confidential proposal) and varying the mix of applicable system strength solutions. By maximising net economic benefits under the various assumptions in each option, specific optimal portfolios were formed under the RIT-T framework.

[38] This approach was discussed with AEMO as part of the SSSP working group in early 2023. AEMO also confirmed that assuming all batteries within the IBR forecast are grid-following is appropriate at this point in time. AEMO suggested that, over time, this may change (which would be reflected in different IBR forecasts) but at this stage it is preferable to be conservative regarding the assumed contribution from these BESS.

Figure 4.3 – Portfolio formation process and key assumptions



The portfolio formation Long-Term model is designed to maximise net economic benefits with respect to the cost of:

- dispatching the market to meet energy demand;
- re-dispatching the market to satisfy system strength constraints; and
- new build providers of system strength.

The total system costs cover the key categories of market benefits considered in this RIT-T:

- costs for parties, other than the RIT-T proponent (that is, changes in fixed and variable operating and maintenance costs);
- fuel consumption in the NEM arising through different patterns of generation dispatch, including that needed to cover network losses;
- Australia's greenhouse gas emissions;
- involuntary load curtailment;
- voluntary load curtailment; and
- capital and operational expenditure for RIT-T proponents.

Relative to the market dispatch model used to model the market benefits of each portfolio, the portfolio formation Long-Term model makes the following simplifications for tractability purposes:

- the modelled horizon is split into more manageable steps;
- temporal granularity is reduced (2 hourly);
- heat rates are simplified;
- maintenance periods are not considered explicitly; and
- the number of regions is reduced (only NSW is explicitly modelled).

These simplifications are considered necessary since optimising for both dispatch and investment decision making over a long horizon introduces significant complexity. Detailed analysis on the impact of these simplifications has been undertaken to ensure they make a suitable trade-off between accuracy and tractability. Note that the first four simplifications above are also made in AEMO's Long-Term dispatch model.[39]

4.3.2 Calibration of PLEXOS inputs and validation of PLEXOS outputs via PSS®E

The portfolio optimisation approach, and therefore the necessity to incorporate system strength constraints into PLEXOS was required by the sheer quantity of individual solutions vying to be part of the optimal portfolio. Transgrid has used detailed power system modelling to represent dynamic and non-linear fault current contributions of each solution into more simplified 'system strength coefficients', which change based on the combination of solutions online and the state of the network. Developing these coefficients involved an iterative process of calculation and validation between PLEXOS and PSS®E (power system modelling software).

In order to validate that the output of PLEXOS' portfolio optimisation met the power system's needs, PLEXOS results were automatically analysed within PSS®E, with a full network topology including geographically dispersed IBR locations. This process meant tens of thousands of power system modelling simulations occurred.

Figure 4.4 shows the iterative process that occurred to ultimately arrive at optimal portfolios of individual system strength solutions.

Figure 4.4 - Overview of the modelling approach for this RIT-T

39 AEMO, *Integrated System Plan Methodology,* June2023, p9

Appendix C provides additional detail on the 'post-processing' that was done to the PLEXOS outputs, including the feedback loop for the system strength solution coefficients in PSS®E, the identification of shortfalls in the network analysis, the necessary 'integerisation' (turning a linear modelling output into integer build decisions) and modifications to the location of new build synchronous condenser solutions.

4.3.3 Summary of the key constraints applied to derive the portfolio options

The portfolio options have been developed by separately optimising portfolios of solutions designed to test key assumptions that are expected to help determine what actions should be taken now.

Specifically, the options test different assumptions about:

- the earliest date that synchronous condensers are commissioned:
  - three of the four portfolio options assume the earliest synchronous condensers can be commissioned is 2028/29 (which assumes orders are placed after completion of the RIT-T and contingent project application (CPA)); while
  - one of the portfolio options ('portfolio option 2') assumes that the procurement of synchronous condensers can be commissioned a year earlier (i.e., by 2027/28) and has been designed to test whether this is expected to be net beneficial. Note that this acceleration would only be feasible if Transgrid commenced procurement of synchronous condensers prior to the conclusion of the RIT-T and AER's approval of the contingent project application (CPA).
- the technical feasibility of the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West given this has not yet been determined:
  - three of the four portfolio options assume that this confidential proposal is not able to be confirmed as technically feasible (which aligns with the fact that it has not yet been determined and recognises the significant work involved with firming this up); while
  - one of the portfolio options ('portfolio option 3') assumes that this confidential proposal is demonstrated to be technically feasible and so can assist with providing system strength.
- the number of gas units ultimately contracted with to provide system strength in light of the small pool of potential generators:
  - three of the four portfolio options do not place any constraint on the number of gas units we can contract with; while
  - one of the portfolio options ('portfolio option 4') restricts the number of gas units that can be contracted in order to test whether this materially affects the net market benefit of the portfolio. This portfolio option was included because modelling showed that different gas units were being re-dispatched for system strength, but not often at the same time, suggesting that it may be possible to restrict the number of units able to re-dispatch to promote economic efficiency with regards to non-network contract pricing, without materially changing net benefits.

The key constraints feeding into the four core portfolios developed and investigated as part of this PADR are summarised in the table below.

Table 4.1 – Summary of the key constraints applied to derive the portfolio options assessed in this PADR

Portfolio option	Earliest timing for synchronous condensers	Is the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West assumed to be technically feasible?	Any constraints on the number of gas units that can be contracted with?
1 – Synchronous condensers available from 2028/29	2028/29	No	No
2 – Synchronous condenser delivery accelerated to 2027/28	2027/28	No	No
3 – Confidential proposal technically feasible (and synchronous condensers available in 2028/29)	2028/29	Yes	No
4 – Restricting the number of gas units (and synchronous condensers available in 2028/29)	2028/29	No	Yes

Transgrid has not assessed a portfolio option that assumes synchronous condenser delivery can be accelerated and that the confidential proposal is technically feasible (a notional "option 5"). If both options are looking feasible during PACR market modelling, Transgrid will seek to model this portfolio option.

Each core portfolio option has been designed to meet energy demand and system strength requirements at lowest total system cost (i.e. maximum net market benefits), subject to the key additional constraints outlined above. Specifically, each of the portfolio options has been designed to address in full both the AEMO declared system strength Shortfall from 1 July 2025 to 1 December 2025 as well as the new minimum and efficient level of system strength requirements from 2 December 2025 onwards.

4.4 System strength at Broken Hill

Transgrid has a requirement to host 187 MW of new inverter-based renewables surrounding Broken Hill from 2026/27, which will require approximately 351 MVA of additional fault current contribution (or equivalent stable voltage waveform support) to be provided at Broken Hill.

Transgrid has manually assessed solutions to this need (i.e., outside of the above-described market modelling processes) and included it as part of each portfolio option. This is due to limitations in the PLEXOS model that prevent it from accurately modelling the system strength need in Broken Hill due to the large electrical distance from the nearest system strength node at Buronga.

This has resulted in the selection of the addition of clutches to the Hydrostor Silver City compressed air energy storage project as the draft preferred option for this location, which has been included in all portfolio options in this PADR. Adding these clutches is expected to meet the entire system strength requirement at Broken Hill and cost significantly less than a targeted network synchronous condenser, grid-forming BESS or grid-forming STATCOMs with a supercapacitor (which were also assessed), whilst not providing materially different market benefits to these alternatives.

Transgrid considers this a proportionate approach under the RIT-T and note that the alternative would be to create an unofficial system strength node at Broken Hill in PLEXOS. However, doing so would add unnecessary complexity to the model. Given that there are only four solutions PLEXOS can choose from to meet Broken Hill's future need and the differences in costs were large, Transgrid considers it would not change the optimal solution identified.

5 Four portfolio options have been developed and assessed

This PADR has assessed four different portfolio options that have been developed by separately optimising groups of solutions under different portfolio constraints. The portfolio optimisation process finds that all four portfolio options include:

- a large number of new network synchronous condensers – at least ten, and up to fourteen, by 2032/33 (i.e., the end of our next regulatory control period);
- modifications to synchronous hydro generators, and the addition of clutches to the Broken Hill compressed air energy storage facility in order to allow system strength provision, in total contributing over 550 MW of system strength services;
- contracting with a range of existing generators to ensure they can switch on or operate in synchronous condenser mode where necessary to fill gaps in system strength. This enablement for system strength is almost all made up of hydro generation, given the low marginal cost associated with its system strength support (in generation or synchronous condenser mode), with a smaller amount of gas and black coal also being re-dispatched;
- contracting with committed and anticipated grid-forming BESS where they are in locations that can provide a material amount of stable voltage waveform support to IBRs. These solutions are low cost under the RIT-T as it is only the incremental costs associated with providing system strength that are included;
- contracting with the assumed proponents of modelled BESS included in AEMO's IBR forecasts to upgrade these units to be 'grid-forming' where they are in locations that can provide a material amount of stable voltage waveform support to renewable generators. These reflect relatively low-cost solutions due to only the incremental costs of the upgrade being included; and
- no EOI proposed BESS, or 'targeted BESS' – the total capex of these solutions is included in the RIT-T assessment which means they have a much higher cost than anticipated/committed BESS and modelled BESS included in the IBR forecasts (and were not found to have sufficient off-setting market benefits versus synchronous condensers)[40].

The findings from the portfolio optimisation process in terms of the *differences* across the portfolio options are:

- if synchronous condensers can be accelerated by one-year (from 2028/29 to 2027/28) then it is optimal to bring 5 synchronous condensers forward to 2027/28;
- the need for the total number of synchronous condensers by 2032/33 is reduced by 4 when the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West is assumed to be technically feasible;
- restricting the number of gas units we contract with changes the timing of synchronous condensers required but does not change the total number of synchronous condensers required.

Of the four portfolio options, only one meets the full system strength requirements, being portfolio option 2 which accelerates the commissioning of synchronous condensers by 1 year, to 2027/28. The other three portfolio options see gaps in system strength in 2027/28, which presents risks to outcomes for the power system and consumers (including expected unserved energy).

The four portfolio options optimised via PLEXOS are a blend of non-network (e.g. coal, hydro, gas, grid-forming batteries) and network (e.g. synchronous condensers) system strength solutions. The portfolio

[40] The one exception to this is the inclusion of an EOI proposed grid-forming BESS at or near to Parkes – as outlined in section 4.3.2, this has been determined to be optimal by Transgrid through its PSS®E analysis separate to the portfolio optimisation process undertaken by Baringa (along with adding clutches to the planned Hydrostor compressed air solution in Broken Hill to enable its operation in synchronous condenser mode).

optimisation results have been aggregated in the table below, where appropriate to preserve the confidentiality of individual proposals and to not interfere with the competitiveness of the forthcoming procurement process. The four portfolio options can be summarised as follows:

- **Portfolio option 1:** synchronous condensers able to be commissioned in 2028/29; and
- **Portfolio option 2:** synchronous condensers able to be commissioned a year earlier in 2027/28 (i.e., 'accelerated'); and
- **Portfolio option 3:** portfolio option 1 assumptions plus the confidential proposal *is* assumed to be technically feasible; and
- **Portfolio option 4:** portfolio option 1 assumptions but with the addition of a restriction on the number of gas units we can contract with.

Table 5.1 – Summary of the make-up of the four portfolio options *

Option	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Synchronous condensers – cumulative number of units (each providing 1,150MVA$_{\text{fault current}}$)									
1	–	–	–	8	10	13	14	14	26
2	–	–	5	8	10	13	14	14	26
3	–	–	–	5	7	10	10	10	24
4	–	–	–	10	10	13	13	13	26
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
1	–	50	550	550	550	550	550	550	550
2	–	50	550	550	550	550	550	550	550
3	–	50	550	550	550	550	550	550	550
4	–	50	550	550	550	550	550	550	550
Coal generator enablement for system strength – share of system strength re-dispatch hours (%)									
1	11%	10%	12%	2%	5%	1%	–	4%	–
2	11%	10%	4%	2%	6%	1%	1%	4%	–
3	11%	10%	10%	1%	5%	2%	1%	4%	–
4	11%	11%	9%	2%	5%	2%	–	5%	–
Gas generator enablement for system strength – share of system strength re-dispatch hours (%)									
1	2%	3%	4%	–	–	–	–	3%	–
2	2%	3%	1%	–	–	–	–	3%	–
3	2%	3%	4%	–	–	–	–	3%	1%
4	2%	3%	3%	–	–	–	–	3%	–
Hydro generator enablement for system strength – share of system strength re-dispatch hours (%)									
1	87%	86%	84%	98%	95%	99%	100%	93%	100%
2	87%	86%	95%	98%	94%	99%	99%	93%	100%
3	87%	87%	87%	99%	95%	98%	99%	93%	99%
4	87%	86%	88%	98%	95%	99%	100%	92%	100%
Grid-forming BESS – cumulative capacity (MW)									
1	750	2,600	2,600	3,500	4,800	4,800	4,800	4,800	4,800
2	750	2,600	2,850	3,600	4,750	4,800	4,800	4,800	4,800
3	750	3,050	3,050	4,100	4,800	4,800	4,800	4,800	4,800
4	750	2,550	2,550	3,200	4,800	4,800	4,800	4,800	4,800

** This table does not include the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West in portfolio option 3.*

Of the four portfolio options, only one meets the full system strength requirements (being portfolio option 2, which accelerates the commissioning of synchronous condensers by 1 year, to 2027/28). The other three portfolio options lead to gaps in system strength in 2027/28, which presents risks to outcomes for the power system and consumers (including expected unserved energy), as summarised in Table 5.2.

Table 5.2 – Gaps in system strength which cannot be filled across the four portfolio options

	1 – Synchronous condensers available from 2028/29	2 – Synchronous condenser delivery accelerated to 2027/28	3 – Confidential proposal technically feasible	4 – Restricting the number of gas units
Armidale	Gap in 2027/28	No gap	Gap in 2027/28	Gap in 2027/28
Newcastle	Gap in 2027/28	No gap	No gap	Gap in 2027/28
Sydney West	Gap in 2027/28	No gap	No gap	Gap in 2027/28
Wellington	Gap in 2027/28	No gap	Gap in 2027/28	Gap in 2027/28
Darlington Point	Gap in 2027/28	No gap	Gap in 2027/28	Gap in 2027/28
Buronga	No gap	No gap	No gap	No gap

While portfolio option 1 is currently the most credible option, insights from our market modelling show that if the underlying uncertainties associated with portfolio option 2 and 3 were successfully resolved (independently or both), there would be significant benefits for consumers. As such, Transgrid will work over the course of this RIT-T to clarify and resolve these uncertainties.

Table 5.3 summarises the total capital and operating costs[41] for each option over the 20-year assessment period, in aggregate across the difference components (please note that these costs are shown in *undiscounted* 2023/24 dollars).

Table 5.3 – Summary of the costs of the four portfolio options over the 20-year assessment period – undiscounted 2023/24 dollars, $m

	1 – Synchronous condensers available from 2028/29	2 – Synchronous condenser delivery accelerated to 2027/28	3 – Confidential proposal technically feasible	4 – Restricting the number of gas units
New synchronous condensers				
Capex	$2,023	$2,023		$2,023
Opex	$144	$147	Confidential*	$144
Total	**$2,167**	**$2,170**		**$2,167**
Unit upgrades to allow synchronous condenser mode operation				
Capex	$25	$25		$25
Opex	$0	$0	Confidential*	$0
Total	**$25**	**$25**		**$25**

[41] In preparing this PADR, Transgrid has used the best available information on the timing and costs of non-network and network options, as established in late-2023 following the PSCR consultation and expressions of interest phase, and detailed proponent and Original Equipment Manufacturer (OEM) discussions. Transgrid is continuing to engage with proponents and OEMs on the lead times and costs of all proposed solutions. Market modelling for the third stage of the RIT-T will incorporate latest information as it arises.

	1 – Synchronous condensers available from 2028/29	2 – Synchronous condenser delivery accelerated to 2027/28	3 – Confidential proposal technically feasible	4 – Restricting the number of gas units
Grid-forming BESS				
Capex	$360	$357	Confidential*	$352
Opex	$28	$28		$28
Total	**$388**	**$384**		**$380**
Total costs excl. re-dispatch				
Capex	**$2,408**	**$2,404**	**Confidential***	**$2,399**
Opex	**$172**	**$175**		**$172**
Total	**$2,580**	**$2,579**		**$2,571**

** Portfolio option 3's costs have been kept redacted given it includes the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West.*
Note, costs may not add due to rounding.

Please note that while this chapter presents the full capital and operating costs of each portfolio option out to the end of the assessment period (2044/45), we summarise the total capital and operating costs (in undiscounted 2023/24 dollars) until the end of the next regulatory control period in Table 5.4 below.[42]

[42] Please note that these are the costs out until 2032/33 that have been included in the analysis and do not map directly to the costs we expect to recover via the regulatory control process (e.g., the unit upgrades to allow synchronous condenser mode operation and new grid-forming BESS build would be incurred by proponents of these solutions who would then charge Transgrid an operating cost to cover their costs). We have presented costs over this period here since investment decisions regarding the number of network synchronous condensers required by the end of next regulatory control period are expected to be made as a result of the outcomes of this RIT-T.

Table 5.4 – Summary of the costs of the four portfolio options out to 2032/33 – undiscounted 2023/24 dollars, $m

	1 – Synchronous condensers available from 2028/29	2 – Synchronous condenser delivery accelerated to 2027/28	3 – Confidential proposal technically feasible	4 – Restricting the number of gas units
New synchronous condensers				
Capex	$1,375	$1,400	Confidential*	$1,400
Opex	$28	$31		$28
Total	**$1,403**	**$1,431**		**$1,428**
Unit upgrades to allow synchronous condenser mode operation				
Capex	$25	$25	Confidential*	$25
Opex	$0	$0		$0
Total	**$25**	**$25**		**$25**
Grid-forming BESS				
Capex	$360	$357	Confidential*	$352
Opex	$10	$10		$10
Total	**$371**	**$367**		**$362**
Total costs excl. re-dispatch				
Capex	**$1,760**	**$1,782**	**Confidential***	**$1,777**
Opex	**$38**	**$41**		**$38**
Total	**$1,799**	**$1,822**		**$1,815**

** Portfolio option 3's costs have been kept redacted given it includes the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West.*
Note, costs may not add due to rounding.

In addition, all portfolio options also involve operating (fuel) costs for re-dispatching existing synchronous machines to provide system strength. While these costs are not able to be separated out from general dispatch costs in the market modelling, we note that, in aggregate, each portfolio option involves *lower* total fuel costs than the base case (i.e., accounting for both the greater costs for re-dispatch and the avoided dispatch costs generally).

Our modelling shows that non-network solutions will play a core role in providing system strength into the future and will be brought into the portfolio of solutions via network support contracts. Under the RIT-T framework, network support contract costs are treated as a wealth transfer and in effect are zero-ed out from the assessment (i.e., if proposed network support costs are extremely high, or extremely low, it would have no bearing on the RIT-T assessment).[43]

However, we know that network support contract costs will have a crucial impact on the ultimate cost to end consumers and the AER will be explicitly determining whether such costs are prudent and efficient as part of an ex-ante assessment. As such, the PACR will investigate approaches for minimising these costs, where possible, without materially impacting the make-up of the ultimately preferred option.

The remainder of this section provides more detail on each of the four portfolio options that have been developed and assessed as part of this PADR. It also provides more detail on the base case for the

[43] AER, *Regulatory investment test for transmission – application guidelines*, Final decision, October 2023, pp 60-62.

assessment of these options (i.e., the ‘do nothing’ reference point that all portfolio options are assessed against under the RIT-T).

As outlined in section 4.2, we consider that the optimal portfolio option identifies when and where certain components (e.g., grid-forming BESS) are expected to form part of the solution. Having established and consulted on this, the analysis in the PACR is expected to include testing the sensitivity of the optimal portfolio option to differences in the individual components. This includes whether increasing the size/quantum of the grid-forming BESS in the optimal portfolio materially impacts the net market benefits expected from the portfolio option and/or changes its ranking compared to the second ranked portfolio. The intention of these sensitivity tests at the PACR stage will be to support contracting outcomes where the size and composition of certain components differs (or to establish that the solution does need to necessarily be of that size).

We are planning to consult AEMO on the need to request an augmentation technical report in light of the possible material inter-network impact from the options.[44] If provided, we intend to publish the outcome of this report (from AEMO) alongside the PACR.

While our portfolio options contain a diverse mix of new entry solutions including synchronous condensers, modifications to existing or future synchronous machines and grid-forming batteries, the portfolios do not contain new pumped hydro, gas, biomass or non-network synchronous condensers, unless they are committed or anticipated projects. This is an outcome of the portfolio formation process, which found that the market benefits they bring to the system is not sufficient to outweigh the additional capital or operating costs that they bring.

5.1 Portfolio option 1 – Synchronous condensers available from 2028/29

Portfolio option 1 represents what we consider to be the most realistic set of assumptions at this point in time regarding the timing of when synchronous condensers could be available. It also does not include the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West, on the basis that its technical feasibility has not yet been confirmed. Given the uncertainty that exists regarding these two important expected influences on our ability to procure system strength for NSW, portfolio option 1 is considered the most credible option at this point in time.

Portfolio option 1 is made-up of:

- fourteen synchronous condensers by 2032/33 – none in the current regulatory control period, fourteen in the next regulatory control period;
- modifications to synchronous hydro generators, and the addition of clutches to the Broken Hill compressed air energy storage facility in order to allow system strength provision, in total contributing over 550 MW of system strength services;
- re-dispatching a range of existing hydro generators to ensure they can switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength, as well as a smaller amount of gas and black coal units also being re-dispatched; and

[44] In line with NER 5.16.4(k)(9).

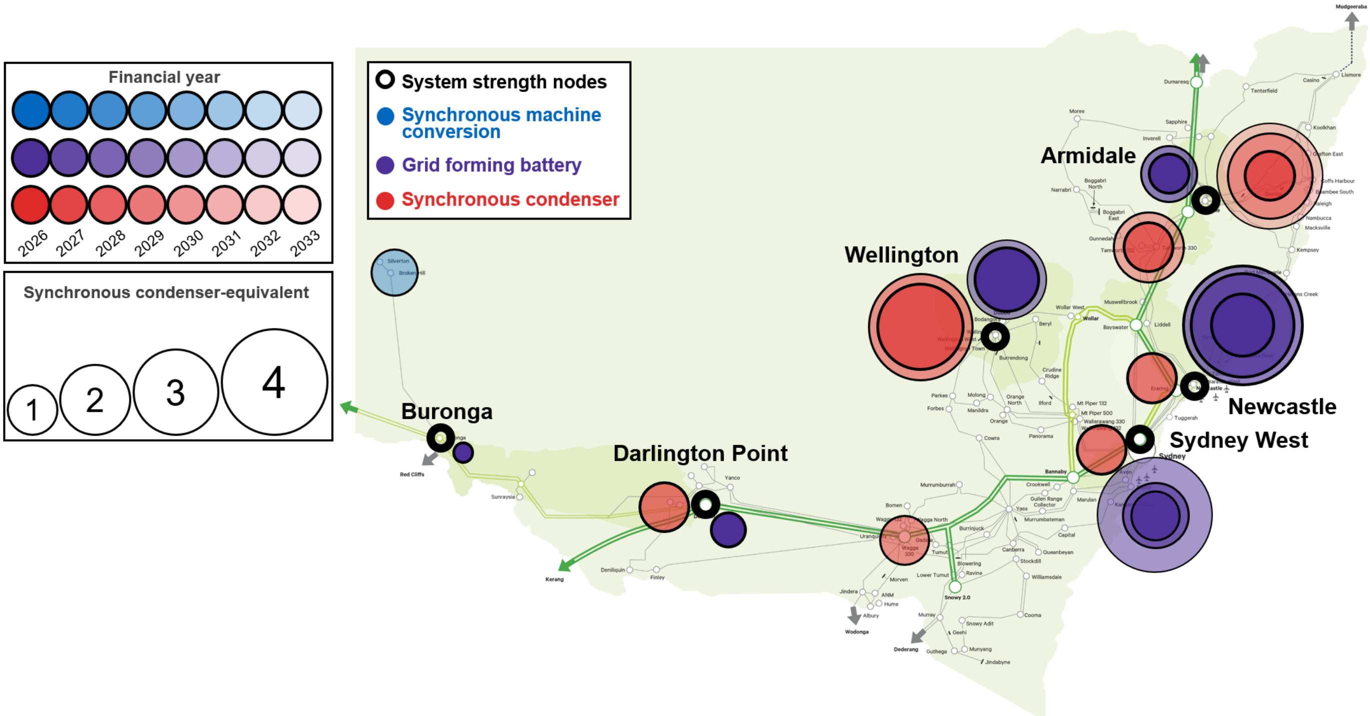
- 4.8 GW of new build grid-forming BESS by 2032/33, comprising primarily of upgrading committed and anticipated grid-following BESS with grid-forming capability and ISP 'modelled' BESS included in the IBR forecasts also upgrading to grid-forming capability.

While this option is currently considered the most credible of the four assessed, there are gaps in system strength that cannot be filled in 2027/28 under this option, which presents risks to outcomes for the power system and consumers (including expected unserved energy).

These gaps in 2027/28 occur at or surrounding Armidale, Wellington, Newcastle, Sydney West and Darlington Point nodes during times when there are low numbers of synchronous machines online due to synchronous generator maintenance or outages (occurring up to 3% of year). These gaps are exacerbated when individual transmission lines between Newcastle and Armidale are required to be taken out of service for short periods of time for maintenance or for the connection of new REZ (termed 'critical planned outage' periods by AEMO). Gaps at Newcastle and Sydney West can be minimised when multiple gas units are re-dispatched for system strength, while gaps at Armidale, Wellington and Darlington Point do not materially change with additional gas units online.

The figure below provides a summary of the magnitude and location of the new build components making up portfolio option 1 (i.e., it does not include the re-dispatch of existing machines included in this portfolio option). It also only shows those components included out to 2032/33 (i.e., until the end of the next regulatory control period).

Figure 5.1 – New build prior to 2032/33 under portfolio option 1



Note: This figure does not show the re-dispatch of existing machines, which are also included in this portfolio option. It also excludes selected system strength solutions for confidentiality reasons.

The location, timing and cost of each of the three key components of portfolio option 1 are discussed in the subsections below.

5.1.1 Fourteen synchronous condensers are required by 2032/33

Portfolio option 1 has fourteen network[45] synchronous condensers by 2032/33, including eight as soon as they can be commissioned in 2028/29. The modelling finds that another 12 synchronous condensers are required over the remainder of the assessment period (i.e., out to 2044/45).

This result is driven by the cost and effectiveness of synchronous condensers in providing protection-quality levels of fault current (i.e. they can meet both minimum and stable voltage waveform requirements).

The table below shows the location and timing of the synchronous condensers included in portfolio option 1 out to 2032/33 in detail (i.e., the end of the next regulatory control period), and aggregated beyond for the rest of the modelling period.

Table 5.5 – Location and timing of synchronous condensers included in portfolio option 1

Synchronous condenser location	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Armidale	-	1	-	-	-	-	-
New England REZ	-	-	-	2	1	-	4
Tamworth	-	1	-	1	-	-	-
Wellington	-	1	-	-	-	-	-
CWO REZ	-	2	1	-	-	-	4
Liddell	-	-	-	-	-	-	2
Newcastle	-	1	-	-	-	-	-
Sydney West	-	1	-	-	-	-	-
Yass	-	-	-	-	-	-	-
Wagga Wagga	-	-	1	-	-	-	-
Darlington Point	-	1	-	-	-	-	1
Dinawan	-	-	-	-	-	-	1
Total	**-**	**8**	**2**	**3**	**1**	**-**	**12**
Cumulative Total	**-**	**8**	**10**	**13**	**14**	**14**	**26**

In present value terms (in 2023/24 dollars),[46] and in total, the 26 synchronous condensers under this option are estimated to cost approximately $904 million and $58 million in capital and operating costs, respectively, over the assessment period.

5.1.2 Upgrades to enable synchronous condenser mode

In addition to the new synchronous condensers, portfolio option 1 also involves upgrading the following units in order to enable them to operate in synchronous condenser mode (where they can provide system security services without needing to run in generation mode):

[45] While both network and non-network synchronous condensers were optimised within the modelling, only network synchronous condensers were selected as part of the preferred portfolio of solutions, as a result of their lower cost and more optimal locations. We note also that only one non-network synchronous condenser was submitted through the EOI process.

[46] All present values presented in this PADR use the central discount rate of 7% (as discussed in section 7.4).

- over 350 MW of modified hydro generators in 2027/28; and
- the Silver City 200MW compressed air energy storage project being developed at Broken Hill in 2027/28 (where clutches are found optimal to be added as discussed in section 4.4).

In present value terms (in 2023/24 dollars), and in total, the upgrades to enable these units to operate in synchronous condenser mode under this option are estimated to cost approximately $17 million in capital costs over the assessment period.

There are not expected to be any additional operating costs for upgrades to enable synchronous condenser operation mode under any portfolio option (i.e., these units are in operation under the base case and are not expected to incur additional operating costs on account of providing system strength as part of the portfolio options).

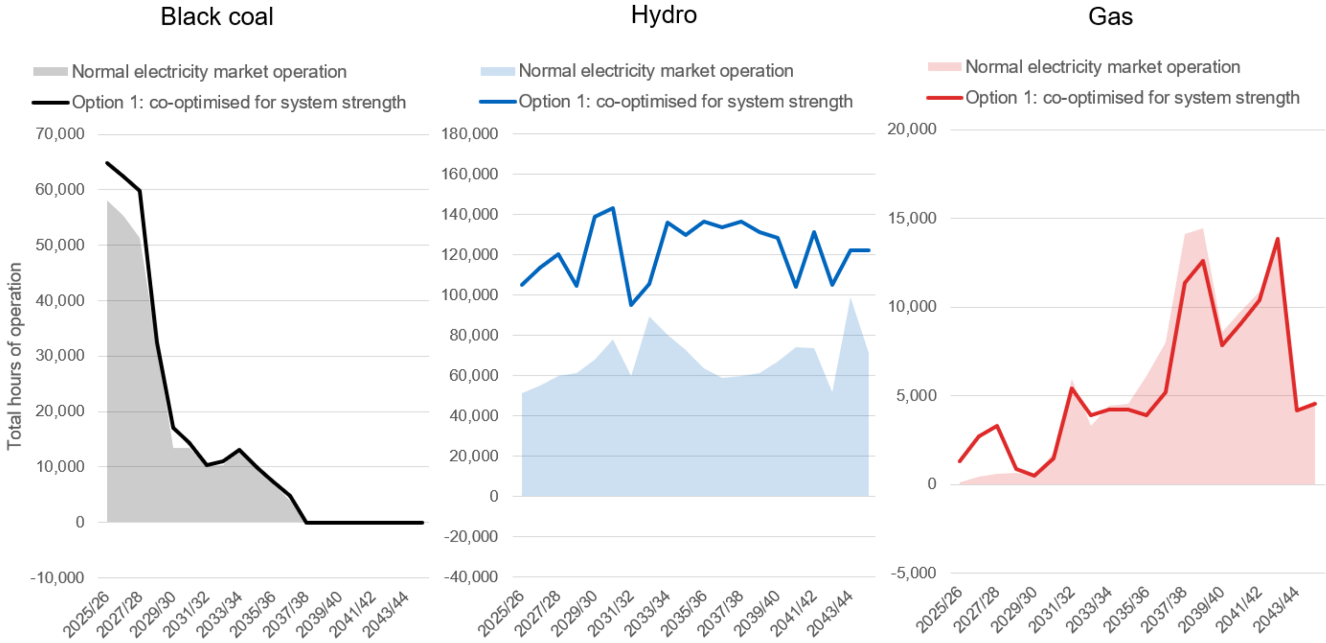
5.1.3 The majority of re-dispatch is from hydro generators

Portfolio option 1 also finds it optimal to contract with a range of existing generators to ensure they can switch on or operate in synchronous condenser mode where necessary to fill gaps in system strength. This re-dispatch is almost all made up of hydro generation (assessed on a re-dispatch-hours basis), given the low marginal cost associated with its output (especially for hydro units that can operate in synchronous condenser mode), with a smaller amount of gas and black coal also being re-dispatched.

The figure below shows the extent of re-dispatch included for this portfolio option over the assessment period, by generating type. We have not individually identified specific generators that would be re-dispatched, given the competitive procurement process for procuring these contracts.

We note that dispatch displayed for 'normal electricity market operation' in these figures (and all figures of this type in the PADR) is the dispatch required to service electricity demand, without any system strength constraints imposed in the modelling.

Figure 5.2 – Enablement for system strength included in portfolio option 1 (dark shading), compared with expected normal electricity market operation (light shading)



In present value terms (in 2023/24 dollars), and in total, the dispatch costs under this portfolio option are estimated to cost approximately $16,168 million in operating (fuel) costs over the assessment period, which is $7,775 million less than the base case. Please note that this estimate, and the corresponding estimates of re-dispatch costs for the other portfolio options, is based on the *total* fuel costs, compared to the base case (i.e., includes both re-dispatch costs for system strength as well as general dispatch costs to meet demand in the NEM).

5.1.4 4.8 GW of new build grid-forming BESS is required by 2032/33

Portfolio option 1 finds that approximately 4.8 GW of new grid-forming battery capacity is required over the assessment period, which is comprised of:

- over 2.5 GW of committed and anticipated BESS being upgraded to have 'grid-forming' capability;
- over 1.5 GW of 'modelled' BESS included in the IBR forecasts being upgraded from grid-following to grid forming (including both 8-hour duration and 2-hour duration modelled projects); and
- over 100 MW of EOI BESS at or surrounding Parkes (as discussed in section 4.3.2).

The composition of these components is driven primarily by the costs of each type of solution. Committed and anticipated BESS proposals have been selected in the portfolio optimisation where they assist in contributing to system strength, as they reflect low-cost solutions in the RIT-T. Since the bulk of the capital costs are assumed to be committed in the base case, it is just the incremental capital and operating costs involved with upgrading these units to be grid-forming that is relevant for the RIT-T assessment.

As part of the PACR assessment, Transgrid will assess whether the individual grid-forming BESS projects provide a material contribution to stable voltage waveform support, via PSCAD studies, and whether they are considered technically feasible. Transgrid will be looking in particular at the grid-forming BESS proposed near Newcastle and Sydney West, as they form the majority of the portfolio of grid-forming BESS, but are electrically far from the growing need for stable voltage waveform support surrounding Armidale and Wellington regions.

The table below summarises the make-up of grid-forming BESS solutions included in portfolio option 1.

Table 5.6 – Location and timing of grid-forming BESS included in portfolio option 1 to 2032/33 – MW (rounded to nearest 50MW)

Region	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Armidale	200	-	-	200	-	-	-	-
Buronga	50	-	-	-	-	-	-	-
Darlington Point	-	150	-	-	-	-	-	-
Newcastle	500	850	-	450	-	-	-	-
Sydney West	-	300	-	250	1,150	-	-	-
Wellington	-	550	-	-	150	-	-	-
Total	**750**	**1,550**	**-**	**900**	**1,300**	**-**	**-**	**-**
Cumulative Total	**750**	**2,600**	**2,600**	**3,500**	**4,800**	**4,800**	**4,800**	**4,800**

In present value terms (in 2023/24 dollars), and in total, the new build BESS and upgrade of existing, committed, anticipated, and modelled BESS under this option is estimated to cost approximately $287 million and $13 million in capital and operating costs, respectively, over the assessment period.

5.2 Portfolio option 2 – Synchronous condenser delivery accelerated to 2027/28

As at least five synchronous condensers are a 'no regret' outcome, portfolio option 2 has been included to investigate whether there would be significantly greater expected net market benefits if the procurement of synchronous condensers could be accelerated by one year, i.e., synchronous condensers could be commissioned in 2027/28, rather than 2028/29, in order to close the system strength gap identified in portfolio option 1. To enable this, Transgrid would need to place orders for synchronous condensers (and commence design and construction work) prior to the RIT-T being complete and the AER's approval of a CPA.

Changing this assumption in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio:

- brings forward five synchronous condensers one year, from 2028/29 to 2027/28, followed by an identical build path over the assessment period (26 required in total);
- accelerating five synchronous condensers by 1 year (to 2027/28) closes the system strength gap identified in portfolio option 1. This acceleration is feasible if procurement of synchronous condensers is commenced prior to the conclusion of the RIT-T and AER's approval of a CPA;
- results in effectively the same re-dispatch as portfolio option 1 (i.e., almost all hydro generators, with a smaller amount of gas and black coal units also being re-dispatched); and
- effectively requires the same amount of grid-forming BESS (with slight timing differences).

The location, timing and cost of each of the three key components of portfolio option 2 are discussed in the subsections below.

5.2.1 Five synchronous condensers are brought forward to 2027/28

While portfolio option 2 continues to find that fourteen synchronous condensers are considered optimal by 2032/33, it brings forward five of them to 2027/28 (from 2028/29), located at Armidale, Newcastle, Sydney West, Wellington and Darlington Point.

Our power system and market modelling identifies that, without the entry of these five synchronous condensers in 2027/28, the NSW/ACT power system will be exposed to periods with gaps in system strength. These gaps occur at or surrounding Armidale, Wellington, Newcastle, Sydney West and Darlington Point nodes during times when there are low numbers of synchronous machines online due to synchronous generator maintenance or outages (occurring up to 3% of year). These gaps are exacerbated when individual transmission lines between Newcastle and Armidale are required to be out of service for short periods of time for maintenance or for the connection of new transmission projects.

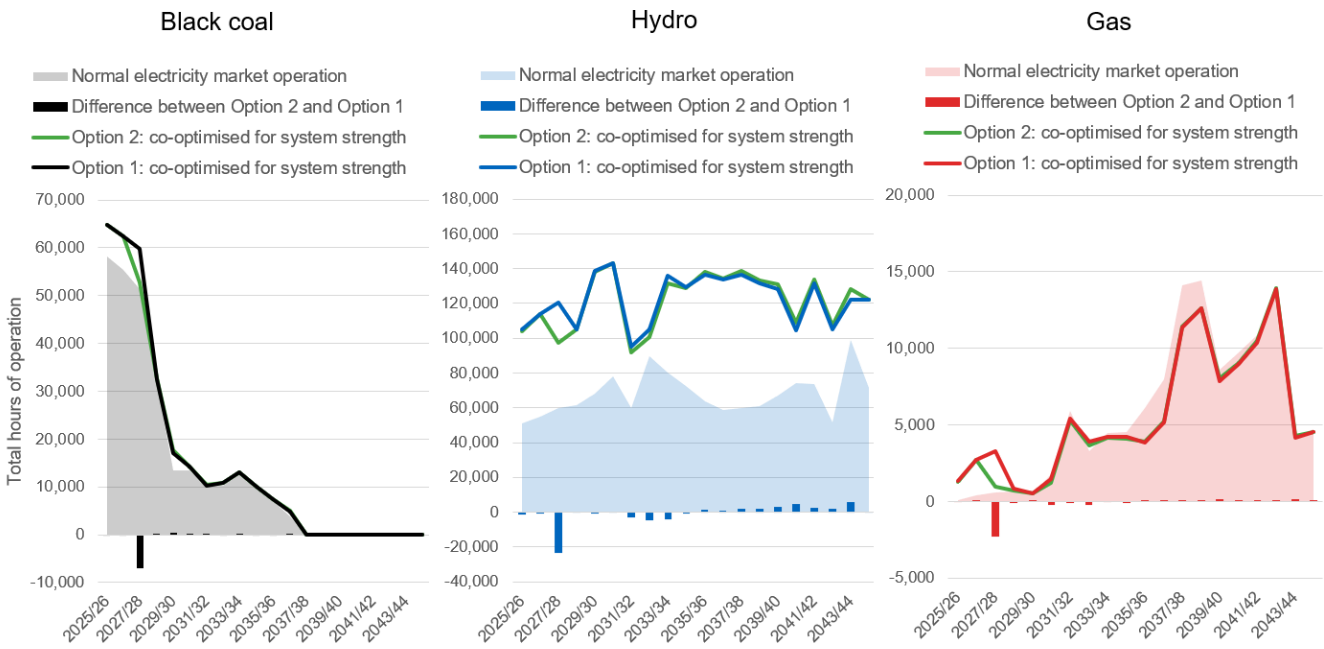
In present value terms (in 2023/24 dollars), and in total, the synchronous condensers under this option are estimated to cost approximately $926 million and $60 million in capital and operating costs, respectively, over the assessment period. In present value terms, these capital and operating costs are $22 million and $2 million higher than portfolio option 1, respectively (because the cost of five synchronous condensers are brought forward one year).

5.2.2 Same pattern of re-dispatch as under portfolio option 1

Portfolio option 2 continues to find that entering into contracts with a range of existing generators to ensure they can switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength is considered optimal. As with portfolio option 1, this re-dispatch is almost all made up of hydro generation given the low marginal cost associated with its output, with a smaller amount of gas and black coal also being re-dispatched.

The figure below shows the extent of re-dispatch included for this portfolio option over the assessment period, by generating type. In this figure, we can see that there is less re-dispatch of coal, hydro and gas in 2027/28 (compared to portfolio option 1), as a result of system strength provided by the accelerated synchronous condensers.

Figure 5.3 – Re-dispatch included in portfolio option 2, compared with that of portfolio option 1



In present value terms (in 2023/24 dollars), and in total, the dispatch costs under this portfolio option are estimated to cost approximately $16,104 million in operating (fuel) costs over the assessment period, which is $7,838 million less than the base case and $63 million less than portfolio option 1.

5.2.3 Effectively the same new build grid-forming BESS as under portfolio option 1

Portfolio option 2 finds that the same amount of new build capacity is required as under portfolio option 1, with only very slight differences in the timing between 2027/28 and 2029/30.

In present value terms (i.e., in 2023/24 dollars), and in total, the new build under this option is estimated to cost approximately $280 million and $13 million in capital and operating costs, respectively, over the assessment period. In present value terms, these capital costs are $7 million lower than portfolio option 1 (due to slight timing differences), but with similar operating costs.

5.3 Portfolio option 3 – Confidential proposal is technically feasible (and synchronous condensers available in 2028/29)

Portfolio option 3 differs from portfolio option 1 in that it assumes that a confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West nodes is technically feasible. This confidential solution is only in concept stage, a detailed feasibility study has not been undertaken and there is a reasonable likelihood that this solution may not ultimately be feasible. A successful feasibility study would be required prior to the commencement of PACR market modelling (approximately end of Q3 2024) to consider it as a credible solution.

Changing this assumption (i.e., to assume the confidential proposal is credible) in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio option 3:

- on the assumption that the confidential proposal is technically feasible, this portfolio closes the system strength gap at Sydney West and Newcastle regions but does not meet system strength requirements at the further locations (Armidale, Wellington, Darlington Point).
- requires four less synchronous condensers by 2032/33 and, importantly, no synchronous condensers at Sydney West and Newcastle. It also defers one of the two synchronous condensers at Tamworth in 2028/29 two years (to 2030/31), as well as two synchronous condensers at the New England REZ (in 2030/31 and 2031/32) and one synchronous condenser at the CWO REZ (in 2029/30) beyond 2032/33. Over the full assessment period, this portfolio option results in two less synchronous condensers than each of the other portfolio options (i.e., 24 in total);
- continues to re-dispatch a range of existing hydro generators to ensure they can switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength (as well as a smaller amount of gas and black coal units also being re-dispatched); and
- effectively requires the same amount of new build grid-forming BESS (though with 400 – 600 MW extra procured between 2026/27 and 2028/29) in addition to the confidential proposal.

The location and timing of each of the three key components of portfolio option 3 are discussed in the subsections below. Due to the confidentiality requested by the proponent of the confidential proposal, Transgrid is only able to present the net market benefits of portfolio option 3 (rather than the detailed breakdown of benefits). As such, we do not discuss the costs of portfolio option 3 in this section.

5.3.1 Four less synchronous condensers are required by 2032/33 than portfolio option 1

Portfolio option 3 finds that five synchronous condensers are considered optimal by 2028/29 and ten by 2032/33, i.e., four less than for portfolio option 1 in 2032/33.

The impact the confidential proposal has on the anticipated need for synchronous condensers can be summarised as follows:

- the two synchronous condensers at Sydney West and Newcastle are no longer needed over the assessment period;
- one of the two synchronous condensers at Tamworth in 2028/29 is deferred two years (to 2030/31);
- two synchronous condensers at the New England REZ (in 2030/31 and 2031/32) are deferred beyond 2032/33; and
- one synchronous condenser at the CWO REZ (in 2029/30) is also deferred beyond 2032/33.

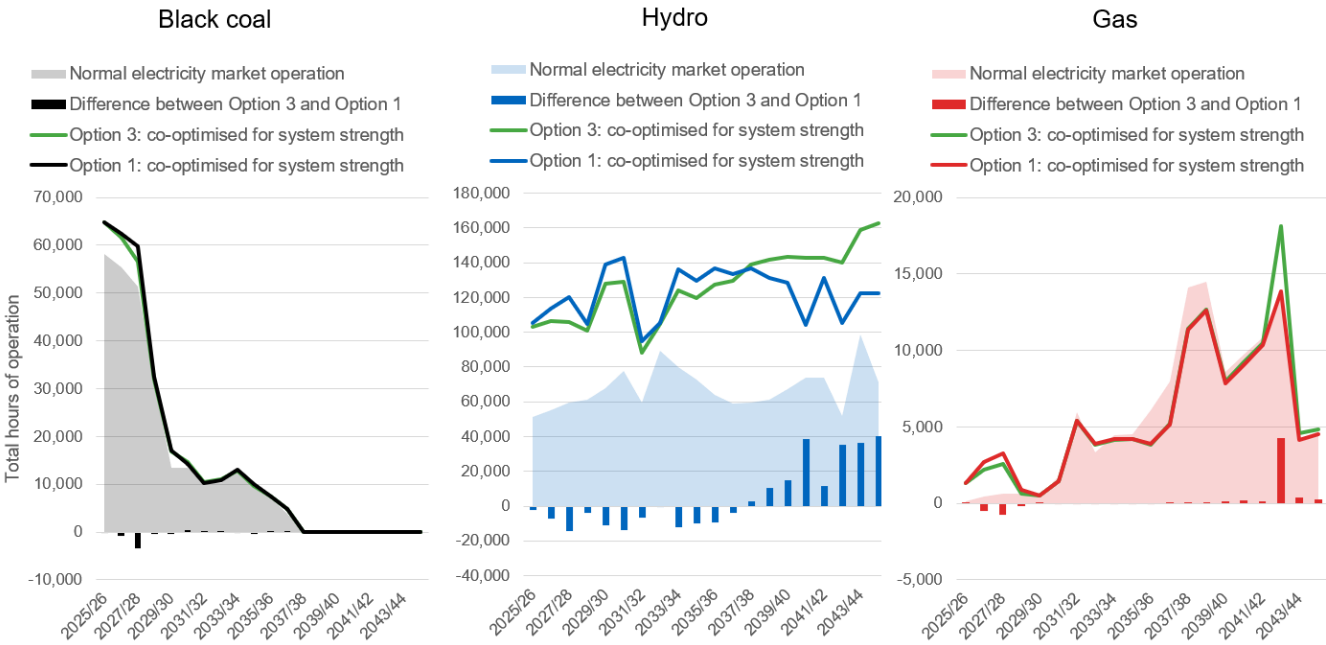
Although the confidential proposal provides substantial system strength support in the Sydney West and Newcastle regions, system strength contributions to other nodes are reduced due to the electrical 'distance (impedance) between these nodes and the source. As an example, approximately 70% of the fault current contribution provided by a synchronous condenser at Sydney West will be lost by the time it reaches Armidale, and approximately 68% of the fault current contribution from a synchronous condenser at Newcastle will be lost by the time it reaches Armidale. As such, synchronous condensers are still required surrounding IBRs, where the system strength support from the confidential proposal is much lower.

5.3.2 More hydro and gas re-dispatched late in the period than under portfolio option 1

As with portfolio option 1, while re-dispatch is almost all made up of hydro generation given the low marginal cost associated with its output, with a smaller amount of gas and black coal also being re-dispatched, there is more hydro and gas dispatched under this option towards the back-end of the assessment period. This is due to the need to bring on additional gas and hydro units to meet growing stable voltage waveform requirements, which is not able to be met by the confidential proposal alone.

The figure below shows the extent of re-dispatch included for this portfolio option over the assessment period, by generating type.

Figure 5.4 – Re-dispatch included in portfolio option 3, compared with that of portfolio option 1



5.3.3 Earlier new build grid-forming BESS capacity required as under portfolio option 1

Portfolio option 3 finds that the same amount of new build grid-forming BESS capacity is required by 2032/33 as under portfolio option 1 and 2, but with 400 MW to 600 MW extra grid-forming capacity procured between 2026/27 and 2028/29.

5.4 Portfolio option 4 – Restricting the number of gas units (and synchronous condensers available in 2028/29)

Portfolio option 4 explores how restricting the number of gas units we contract would change the portfolio of solutions and overall net market benefits, noting that results show that different gas units are being re-dispatched for system strength at different times of the year (rather than all gas units being re-dispatched at the same time).

The purpose of this scenario is to see if a different (likely smaller) portfolio of gas units would have total benefits within the margin of error of portfolio option 1 and, if so, it may affect how we contract with these generators in order to drive a more competitive outcome.

Changing this assumption in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio option 4:

- has similar (though marginally greater) gaps in system strength in 2028/29 which cannot be met at Armidale, Newcastle, Sydney West, Wellington and Darlington Point nodes as portfolio option 1;
- requires two synchronous condensers to be deployed one year earlier, to 2028/29, one at each of Wagga Wagga and in the CWO REZ. It also delays the need for one synchronous condenser in New England REZ from 2031/32 to 2033/34, but brings forward on additional New England REZ synchronous condenser from 2034/35 to 2033/34;
- continues to re-dispatch a range of existing hydro generators to ensure they scan switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength (as well as a smaller amount of gas and black coal units also re-dispatched). However, there is less gas re-dispatched at the start of the period than under portfolio option 1; and
- effectively requires the same amount of new build grid-forming BESS (with slight differences in timing).

The location, timing and cost of each of the three key components of portfolio option 4 are discussed in the subsections below.

5.4.1 Adjusted timing of synchronous condenser build path

Portfolio option 4 sees adjustments in the timing of the synchronous condenser build path when compared against portfolio option 1, specifically:

- one synchronous condensers at Wagga Wagga and one synchronous condenser in the CWO REZ is required to be deployed one year earlier, to 2028/29;
- the timing of synchronous condensers required in the New England REZ is slightly different; the need for one synchronous condenser is delayed from 2031/32 to 2033/34, but a second synchronous condenser is required on year earlier, from 2034/35 to 2033/34;
- the same number of synchronous condensers are required over the modelling period, being 26 in total;

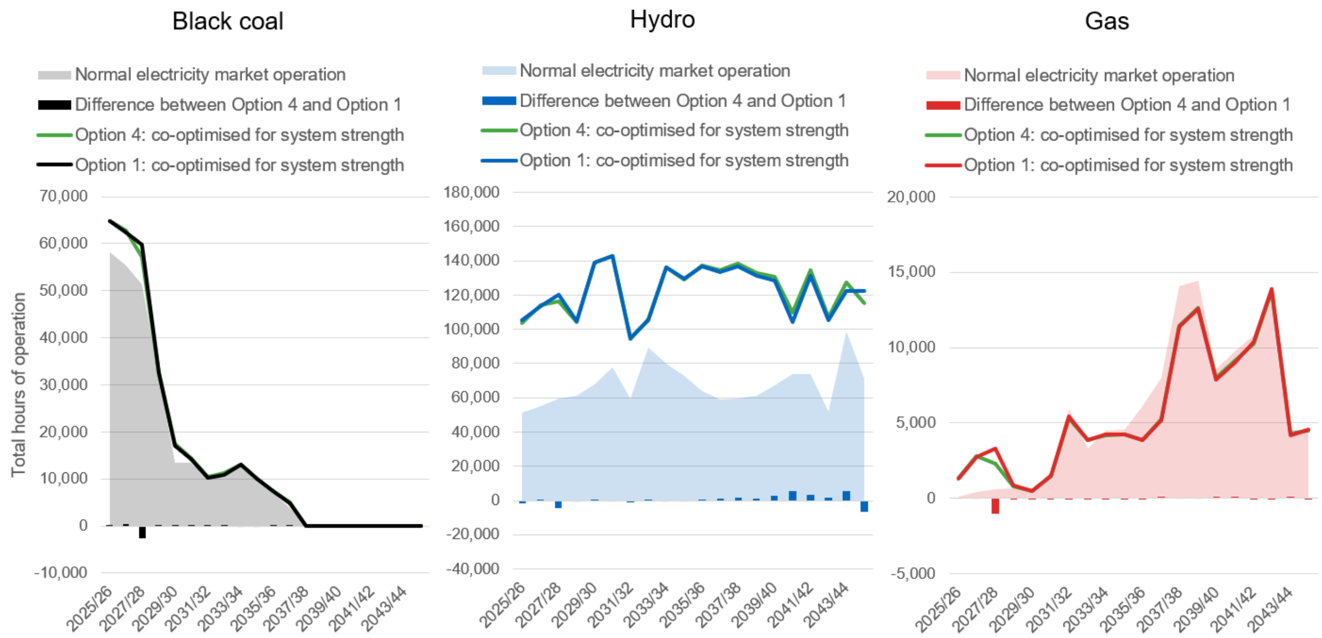
In present value terms (in 2023/24 dollars), and in total, the synchronous condensers under this option are estimated to cost approximately $907 million and $58 million in capital and operating costs, respectively, over the assessment period. In present value terms, these capital costs are $3 million greater than portfolio option 1 (but have similar operating costs).

5.4.2 Slightly less gas is re-dispatched early in the period than under portfolio option 1

While portfolio option 4 continues to find that re-dispatch is almost all made up of hydro generation given the low marginal cost associated with its output, with a smaller amount of gas and black coal also being re-dispatched, it does find that slightly less gas is re-dispatched (16% less hours) in 2027/28 than under portfolio option 1. This is due to the restriction in number of gas units available for system strength re-dispatch, and the relative location of the remaining gas units to the areas of greatest system strength need.

The figure below shows the extent of re-dispatch included for this portfolio option over the assessment period, by generating type.

Figure 5.5 – Re-dispatch included in portfolio option 4, compared to that of portfolio option 1



In present value terms (in 2023/24 dollars), and in total, the dispatch costs under this portfolio option are estimated to cost approximately $16,138 million in operating (fuel) costs over the assessment period, which is $7,804 million less than the base case and $30 million less than portfolio option 1.

5.4.3 Effectively the same new build grid-forming BESS as under portfolio option 1

Portfolio option 4 finds that effectively the same amount of new build capacity is required as under portfolio option 1, though with very slightly less procurement between 2026/27 and 2028/29.

In present value terms (in 2023/24 dollars), and in total, the new build under this option is estimated to cost approximately $273 million and $13 million in capital and operating costs, respectively, over the assessment period. In present value terms, these capital costs are $14 million less than portfolio option 1 (operating costs are effectively the same).

5.5 Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PADR compares the costs and benefits of each portfolio option to a 'do nothing' base case for each scenario. The base case is the (hypothetical) projected case if no action is taken, i.e.[47]

> *"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, existing synchronous machines would be re-dispatched to attempt to meet the growing need for system strength, until the need can no longer be met as more IBRs connect and existing synchronous plant retires. Over time, we expect that the following situations could arise:

- existing and committed synchronous generators would be directed to operate;
- constraints in system operation would occur (e.g. limitations to transmission network outage programmes, avoidance of generator maintenance where possible);
- renewable generation would be constrained (as synchronous generation retires and the power system is increasingly reliant on renewables, this could lead to insufficient generation and ultimately unserved energy); and
- load shedding to ensure the system can remain in a secure operating state.

While these are not situations we plan to encounter, and the NER obligations and this RIT-T have been initiated specifically to avoid them, the assessment is required under the RIT-T to consider this base case as a common point of reference when estimating the net benefits of each credible option.

We have estimated the resulting situation where, dependent upon it being a minimum or efficient level shortfall, load is shed and/or renewable generation is constrained as part of the base case in the PADR assessment, since they impact the operation of the wholesale market under the base case (i.e., the point of reference for each portfolio option's wholesale market benefits).

Transgrid does not intend to let power system security decline in this way and as such, we have used only simplistic assumptions to model the situation above in the base case.

At a certain point, unserved energy due to insufficient system strength becomes so large that we have capped the value of unserved energy in the base case, to make comparisons meaningful across the portfolio options that do meet the minimum and efficient requirements (as outlined in section 7.1.3).

[47] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 22.

6 Estimating option costs

This section outlines how the various option components (both network and non-network) have been costed for the purposes of the PADR assessment.

The cost estimation approach adopted includes a mixture of detailed estimation by Transgrid's project development team, use of specific costs proposed by proponents and OEMs and the use of cost information contained in the AEMO 2023 Inputs, Assumptions and Scenarios Report (IASR).

The portfolio formation process did not result in any EOI proposed BESS[48] (or 'targeted'[49] network or non-network grid-forming BESS) being selected for any of the four portfolios. The model assessed these solutions to be higher cost than existing/committed/anticipated BESS and 'modelled' BESS included in the IBR forecasts and were not found to provide additional market benefits that would justify their greater costs. This is because the full capital and operating cost of EOI proposed BESS are required to be included in the RIT-T assessment, while existing/committed/anticipated BESS and 'modelled' BESS included in the IBR forecasts are included either no cost (where they are grid-forming), or their incremental cost to become grid-forming.

In preparing this PADR, Transgrid has used the best available information on the timing and costs of non-network and network solutions, as established in mid-2023 following the PSCR consultation and expressions of interest phase, and detailed proponent and OEM discussions. Noting the pace of the energy transition and the growing demand for system security infrastructure, Transgrid is continuing to engage with proponents and OEMs on the lead times and costs of all proposed solutions. Market modelling for the PACR stage of the RIT-T will incorporate latest information as it arises.

6.1 Network costs

Network costs have been estimated by a variety of sources, including OEM quotes (for synchronous condensers), our internal estimating tool 'MTWO' for the synchronous condenser balance of plant costs, supplier estimates (for grid-forming STATCOMs) and from AEMO's 2023 IASR for grid forming batteries.

6.1.1 Synchronous condensers

The cost estimates for synchronous condensers are based on an analysis of the components and associated substation work at each location (which includes the requirement for flywheels). In total, we have costed synchronous condensers for the following 21 separate locations, across six nodes in our network. Each synchronous condenser is modelled to provide 1,150MVA fault level contribution at the point of connection to the transmission network.

Table 6.1 – Locations of synchronous condensers considered in the PADR assessment

Node	Locations
Armidale	Armidale 330 kV Glen Innes 132 kV Tamworth 330 kV

48 The one exception to this is the inclusion of an EOI proposed grid-forming BESS at or near to Parkes – as outlined in section 4.3.2.

49 'Targeted' grid-forming BESS refers to BESS that are assumed to be in optimal locations from a system strength perspective and sized to meet the system strength requirements. Transgrid could be one proponent of these BESS, but we are also seeking other proponents through this RIT-T.

Node	Locations
Buronga	Buronga 220 kV Broken Hill 220 kV
Darlington Point	Darlington Point 132 kV Darlington Point 330 kV Wagga Wagga 330kV Yass 330kV Dinawan 330kV
Newcastle	Newcastle 330 kV Liddell 330 kV Bayswater 330 kV Muswellbrook 330 kV
Sydney West	Sydney West 330 kV Vales Point 330 kV Kemps Creek 330 kV Kemps Creek 330 kV (with transmission line 14 cut-in) Cooma 132 kV
Wellington	Wellington 330 kV Wollar 500 kV

The costing has considered a range of drivers for each location, including:

- interaction with related projects (such as other transmission upgrade projects);
- the scope of works required;
- general site arrangement and access issues;
- civil works;
- building works;
- plant and equipment (major and minor);
- electrical works; and
- secondary systems.

The unit prices used for these estimates are based on information provided by synchronous condensers suppliers up to mid-2023, as well as balance of plant and construction costs, derived from Transgrid's MTWO database. No specific contingency allowance has been included in the network cost estimates.

The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- period order agreement rates and market pricing for plant and materials;
- labour quantities from recently completed projects; and
- construction tender and contract rates from recent projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

We estimate that actual costs will be within +/- 25% of the central capital cost estimate (with the exception of four network synchronous condensers noted below). While we have not explicitly applied the AACE cost estimate classification system[50], we note that an accuracy of +/- 25% for cost estimates is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the AACE classification system.

The exception to this is three locations near the Newcastle node (Liddell 330 kV, Bayswater 330 kV and Muswellbrook 330 kV), three locations near the Darlington Point node (Wagga Wagga 330kV, Yass 330kV and Dinawan 330kV) and one location near the Buronga node (Broken Hill 220 kV) where a broader estimate has had to be developed due to these locations being added to the RIT-T assessment late in the PADR preparation process. The costs have been calculated using the cost of other representative units as a proxy, and will be firmed up for the PACR (if part of the PADR portfolio options), i.e.:

- the Liddell and Bayswater synchronous condensers were assigned the same cost as the Kemps Creek synchronous condenser given they have the same expected substation works; the Muswellbrook synchronous condenser costs were calculated as the average between the Newcastle and Sydney West synchronous condenser costs to account for likely bay upgrades required (therefore, the costs represent a scale of work halfway between that required at Sydney West (multiple bay upgrades) and Newcastle (no bay upgrades));
- the Wagga Wagga, Yass and Dinawan synchronous condensers were assigned the same cost as a Darlington Point synchronous condenser given their approximate location to the Darlington Point node, and the expected substation works required were expected to be similar to those at Darlington Point; and
- the Broken Hill synchronous condenser cost is calculated as the cost of a Buronga synchronous condenser, linearly scaled down to account for the difference in the rated capacity (since Broken Hill only requires 60 MVA synchronous condensers). An additional 125% was added to this scaled cost to compensate for losses in economies of scale.

For all four of these synchronous condensers, the cost estimate accuracy was increased from +/- 25% (i.e., the accuracy of the other synchronous condensers) to +/- 50% to account for the higher-level estimates developed for these units. Although these costs were estimated, the portfolio optimisation approach did not select these synchronous condensers to be part of the preferred portfolio of solutions.

Land costs and biodiversity offset costs do not apply for network synchronous condensers since they have been assessed to be co-located on existing Transgrid land that is already hosting other network assets.

We have assumed an annual operating and maintenance cost for synchronous condensers of 0.6% of the upfront capital expenditure. This is consistent with the AER's final decision on ElectraNet's system strength contingent project,[51] as well as discussions with suppliers of synchronous condensers.

Importantly, with regards to the recommended locations of synchronous condensers within all portfolio options and sensitivities – Transgrid will continue to refine and assess the technical feasibility, and cost of deploying synchronous condensers at various locations. In the event that any location becomes unfeasible

[50] Transgrid does not generally apply the Association for the Advancement of Cost Engineering (AACE) international cost estimate classification system to classify cost estimates. Doing so for this RIT-T would involve significant additional costs, which would not provide a corresponding increase in benefits and so this has not been undertaken.
[51] AER, *ElectraNet Contingent Project Main Grid System Strength*, August 2019, p. 29.

(from a technical or cost point of view), Transgrid will revert to the 'next best' location, as determined by project costings and detailed power system modelling.

6.1.2 Grid-forming STATCOMs with a supercapacitor

A grid-forming Static Synchronous Compensator (STATCOM) with a supercapacitor is designed to provide grid-forming control and provide short-term active power capability by injecting or absorbing active and reactive power as needed, thereby maintaining system strength during grid disturbances.

The cost has been based on the costs proposed by a confidential supplier. The initial estimate from the supplier included costings for the manufacture and installation of a 300 MVAr system as well as the cost of the secondary systems required for operation. Since the cost was provided in USD, it was converted to AUD using an AUD/USD exchange rate of 0.65 consistent with AEMO's 2023 'cost and technical parameter review'[52]. To enable the assessment with varying sizes of these STATCOMs, we have linearly scaled the cost. If these STATCOMs were to form part of one of the draft portfolio options, we would work further with the supplier to refine estimates for the PACR.

As for synchronous condensers, we are assuming that these solutions would be deployed on existing Transgrid owned land that currently houses other network infrastructure (and so no land or biodiversity offset costs have been included).

The supplier also proposed annual operating costs of 0.6% of the upfront capital costs.

The STATCOMs have been modelled in PLEXOS in 1 MVAr blocks to ascertain the optimal solution size and location whilst also considering cost effectiveness. This is consistent with how grid-forming BESS have also been modelled.

The table below summarises the locations of grid-forming STATCOMs with supercapacitor considered in the PADR assessment.

Table 6.2 – Locations of grid-forming STATCOMs with supercapacitor considered in the PADR assessment

Node	Locations
Armidale	Armidale 330 kV
Buronga	Buronga 220 kV
Darlington Point	Darlington Point 330 kV
Newcastle	Newcastle 330 kV
Sydney West	Sydney West 330 kV
Wellington	Wellington 330 kV

Importantly, our modelling shows that the portfolio optimisation approach did not select these grid-forming STATCOMs with a supercapacitor to be part of the preferred portfolio of solutions.

6.1.3 'Targeted' grid-forming BESS

'Targeted' grid-forming BESS refers to BESS that are assumed to be in optimal locations from a system strength perspective and sized to meet the system strength requirements. Transgrid could be one proponent of these BESS (as a network solution), but we are also seeking other proponents through this

[52] Aurecon, *2023 Cost and Technical Parameters Review*, December 2023, p. 14.

RIT-T (noting that no 'targeted' grid-forming BESS were selected as part of the portfolio options or sensitivities).

All costs and other assumptions regarding the technical operation of grid-following BESS have been sourced from the 2023 IASR assumptions, with the exception of the additional cost of converting a grid-following BESS to a grid-forming BESS. This additional cost is explained in Section 6.2.4.

As part of this PADR consultation, Transgrid is seeking feedback on these assumptions, noting that the portfolio optimisation approach did not select these targeted grid-forming BESS to be part of the preferred portfolio of solutions.

As for synchronous condensers, we are assuming that all targeted network grid-forming BESS will be deployed on existing Transgrid owned land that currently houses other network infrastructure (and so no land or biodiversity offset costs have been included).

The table below summarises the locations of targeted grid-forming BESS considered in the PADR assessment.

Table 6.3 – Locations of grid-forming BESS considered in the PADR assessment

Node	Locations
Armidale	Armidale 330 kV
Buronga	Buronga 220 kV
Darlington Point	Darlington Point 330 kV
Newcastle	Newcastle 330 kV
Sydney West	Sydney West 330 kV
Wellington	Wellington 330 kV

6.2 Non-network costs

This section summarises how non-network elements have been costed as part of the PADR assessment.

6.2.1 Updated treatment of network support contract costs

While proposed network support contract costs do not have any bearing in the RIT-T NPV assessment, as they net off equally between costs and benefits,[53] and have been kept confidential, we note that the AER will now undertake an ex-ante assessment of these costs as being prudent and efficient as part of the 'improving security frameworks for the energy transition' rule change (on TNSP request).

Specifically, from 1 December 2024, the AER will make determinations in advance when requested on whether expenditure under a TNSP's proposed system security network support contract is consistent with the operational expenditure objectives, criteria, and factors to promote economic efficiency.[54] This will

[53] The AER's RIT-T guidance states that any cost to one market participant that directly translates to an equal benefit for another market participant is classified as a wealth transfer and should be netted out to zero in the cost benefit analysis. The AER treats network support costs as wealth transfers in the RIT-T assessment. See: AER, *Regulatory investment test for transmission – application guidelines*, Final decision, October 2023, pp 60-62.

[54] AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024*, Rule Determination, 28 March 2024, p. iv.

safeguard customers from excessive network support costs, which are not currently reflected in the RIT-T assessment of the preferred option.

Through and beyond the PADR consultation period, we will be seeking updated network support contract costs from proponents. [55] We will assess these contract costs to identify whether we believe they would successfully pass AER's assessment. Where we consider proposed network support contract costs are not expected to pass this new process (i.e., where they are not considered 'prudent and efficient'), then we will not be considering these solutions as credible as part of the PACR process.

As input into the PACR market modelling, Transgrid will assess the technical and commercial credibility of all non-network options selected as part of the PADR's preferred portfolio of solutions (which were assumed to be technically and commercially credible). Where non-network solutions are determined to not be credible, these options will not progress through the RIT-T and procurement process. Alternative solutions (either non-network or network) would be required to fill its place in the optimal portfolio of solutions.

6.2.2 Treatment of anticipated and committed projects

In preparing this PADR, we have engaged with solution proponents on the commitment status of their projects. Specifically, we have liaised directly with proponents to determine whether their solutions are considered 'anticipated' or 'committed' under the RIT-T, i.e., whether they meet the criteria for these classifications under the RIT-T.

The RIT-T defines a 'committed' project as one that meets the following criteria:[56]

- the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;
- construction has either commenced or a firm commencement date has been set;
- the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction;
- contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments; and
- the necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

An 'anticipated' project is defined as one that does not meet all of the criteria of a committed project but is in the process of meeting at least three of the criteria.[57]

All projects that we have considered as 'anticipated' or 'committed' in the PADR assessment have the same status in AEMO's October 2023 generation information workbook. All proponents who suggested that their projects should be considered 'anticipated' but were not classified as so in this version of AEMO's

[55] By 30 June 2024, AEMO will publish the part of the security enablement procedures which provide any minimum or recommended requirements to be included in TNSPs' contracts for security services. Transgrid will wait until after this publication to commence seeking updated network support contract prices from proponents.
[56] AER, *Regulatory Investment Test for Transmission*, August 2020, p. 13.
[57] AER, *Regulatory Investment Test for Transmission*, August 2020, p. 13.

generation information workbook, were assessed against the RIT-T criteria based on what was provided by proponents and were all ultimately determined to be ‘proposed’ for the PADR assessment.

Where projects have been determined as ’anticipated’ or ‘committed’ under the RIT-T, they have been included in the base case and option cases for our assessment. Since costs and/or market benefits associated with the provision of system strength from anticipated or committed projects are netted off between the base case and portfolio options, we have only estimated project costs to the extent that they differ to what has been assumed in the base case.

In total, the following number of projects have been classified as ’anticipated’ or ‘committed’ for the PADR assessment (and thus included in the base case).

Table 6.4 – Summary of ’anticipated’ or ‘committed’ projects in the PADR assessment

Type of project	Anticipated	Committed
BESS	3	3
Pumped Hydro	-	1
Gas	-	2

In addition, we have also included in the base case two BESS which are considered ‘proposed’ (i.e., not yet committed or anticipated based on the above criteria). However we consider them consistent with government policies that meet the criteria in NER 5.22.3(b), for example receiving government grants or contracts.

6.2.3 Non-network grid-forming BESS

As outlined in 6.2.2, where BESS projects have been determined as ’anticipated’ or ‘committed’ under the RIT-T, they have been included in the base case and option cases for our assessment. As above, since costs and/or market benefits associated with the provision of system strength from anticipated or committed projects are netted off between the base case and portfolio options, we have only estimated project costs to the extent that they differ to what has been assumed in the base case.

For EOI proposed BESS projects (i.e., those that are not included in the base case), the assumed costs can significantly influence the RIT-T outcome. In order to ensure fairness and consistency of cost data at this stage of the RIT-T, 2023 IASR cost assumptions have been applied to all proposed BESS projects (along with an allowance for conversion to grid-forming capability, as outlined in section 6.2.4 below).

6.2.4 Incremental capital cost to convert grid-following BESS to grid-forming BESS

For all BESS projects, grid-forming capability is required to provide system strength services. At this stage, we have assumed that all grid-forming BESS will provide the same amount of system strength, per MW of capacity. In the next stage of the RIT-T and contracting processes, we will undertake detailed PSCAD™ studies for each grid-forming BESS to confirm technical feasibility and quantify its system strength capability (which we expect will vary between proposals). Transgrid will require PSCAD models to enable BESS proponents to proceed to the PACR and contracting stage.

This subsection outlines how the incremental capital cost to convert grid-following BESS to grid-forming BESS has been estimated for the PADR assessment. Specifically, it has been estimated differently for proposed and modelled projects, compared to anticipated and committed projects.

6.2.4.1 Proposed and modelled projects

Proposed and modelled grid-forming BESS have been costed using the IASR assumptions. The Draft 2024 ISP investment modelling does not explicitly make a distinction between grid-following and grid-forming inverters, and all IBR is effectively treated as grid-following.[58] Informed by discussions with various parties in the industry, we have therefore assumed that upgrades or enhancements required to be grid-forming has an extra cost equal to 5% of the upfront capital costs of the grid-following BESS, to reflect the additional effort in the connection application process and the possible need for additional inverter capacity. That is, the cost of these projects has been included in the option cases as the IASR costs plus 5%.

For modelled projects (i.e., generic BESS included in the AEMO IBR forecasts that are assumed to upgrade from grid-following to grid-forming if paid to do so), which exist in the base case, only the 5% of the assumed upfront capital cost has been assumed in the option cases, i.e., the incremental cost of the grid-forming inverters required to provide system strength, as well as additional modelling costs.

We have also assumed that all proposed and modelled BESS projects will be commissioned in grid-forming mode from day one (i.e., it will be a condition of the system strength services agreement).

6.2.4.2 Anticipated and committed projects

All proponents of anticipated and committed BESS projects have stated that their projects are able to have grid-forming capability. If a proponent has an existing contractual commitment to commission the BESS in grid-forming mode from day one (e.g. a grant funding or network support agreement that requires grid-forming capability), we have assumed the grid-forming component of their project is “committed” for the purpose of the RIT-T, and hence any costs relating to grid-forming capability are included in both the base case and option case.

Where anticipated and committed BESS do not have a contractual commitment to connect in grid-forming mode, we assume that the grid-forming component of their project is not “committed” for the purpose of the RIT-T (regardless of the proponent’s stated intention), and hence any costs relating to grid-forming capability are only included in the option case. As such, we assume they will initially connect in grid-following mode, and will subsequently need to go through the NER 5.3.9 process to enable grid-forming mode, which will take 12 months (informed by Transgrid’s experience with the Wallgrove Grid Battery) and cost 1% of the upfront capital cost (informed by discussions with various parties in the industry). This 1% assumption seeks to reflect the costs of the NER 5.3.9 application process and assumes no significant hardware upgrades are needed.

6.2.5 Existing plant with no synchronous condenser mode

The costs for these existing coal and gas plant have come primarily from the 2023 IASR.

The exception to this is where costs are not available in the 2023 IASR assumptions (e.g., start-up costs, installing clutches, upgrading to add synchronous condenser capability etc). These costs have come either from proponents or from the 2018 GHD cost and technical parameter review undertaken for AEMO (as the most recent comprehensive assessment of technology costs and technical parameters).[59]

[58] AEMO, *2023 System Strength Report*, December 2023, p. 11.

[59] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

6.2.6 Existing plant with the option to operate in synchronous condenser mode

There are two types of existing coal, gas and pumped hydro plant that are able to operate in synchronous condenser mode – namely:

- Type 1 (existing) – currently able to operate interchangeably as a generator or in synchronous condenser mode (i.e., no capital cost required); and
- Type 2 (upgrade) – able to operate interchangeably as a generator or in synchronous condenser mode following an upgrade (i.e., incremental capital cost required).

The table below summarises the key sources of cost assumptions for the seven different existing plant with the option to operate in synchronous condenser mode (or convert to a synchronous condenser). The names of each generator have been redacted for confidentiality purposes.

Table 6.5 – Summary of the cost assumptions for existing plant with the option to operate in synchronous condenser mode (or convert to a synchronous condenser)

Generator/ key assumption	A	B	C	D	E	F
Type	Type 1			Type 2		
CAPEX	Nil			Proponent		
Fixed Operating & Maintenance (FOM, Generating)	2023 IASR			2023 IASR		
Variable Operating & Maintenance (VOM, Generating)						
Incremental FOM (synchronous condenser)	$0 as per the 2018 GHD cost and technical parameter review				Proponent	$0 as per the 2018 GHD cost and technical parameter review
VOM (synchronous condenser)	Nil				Proponent	Nil

While the capital cost estimates for Type 2 have come directly from proponents, we found that the generating FOM and VOM estimates provided varied greatly across proponents and without clear reason. We therefore assumed FOM and VOM (when generating) from the 2023 IASR to standardise these costs.

6.2.7 New build pumped hydro plant, gas, biomass and compressed air storage

All synchronous pumped hydro units have the ability to provide fault current whilst generating, pumping and whilst operating in a synchronous condenser mode (if this functionality exists, or following upgrade).

We have assumed 2023 IASR capital and operating costs for all new build pumped hydro plant, as well as new build gas and biomass. The two exceptions to this are the capital cost of Snowy 2.0 (where we have assumed $12 billion, as per the latest estimate at the time of commencing modelling from Snowy 2.0)[60] and the capital cost for biomass (which was provided by a proponent).

We note that the VOM expenditure and the auxiliary load of a hydro unit is dependent on the mode that it is operating in due to:

- additional maintenance based on hours run in synchronous condenser mode (for VOM); and
- the additional energy required to operate as a synchronous condenser (for auxiliary load).

All assumed auxiliary losses in generating (1%) and synchronous condenser mode (4%) for hydro have come from the 2018 GHD cost and technical parameter review undertaken for AEMO (as the most recent comprehensive assessment of technology costs and technical parameters)[61], with the exception of three units where the proponent provided values for losses in synchronous condenser mode (1.5 - 3%).

The incremental VOM incurred by a hydro unit operating in synchronous condenser mode has been assumed to be zero as Table 60 in the GHD cost and technical parameters report states that the additional cost of a hydro unit operating in synchronous condenser mode is 'marginal'. While this is the only information we can find at this stage on the incremental VOM of these units, it does not currently appear to be material to the RIT-T analysis. We can revisit it as part of the PACR if it is becomes material (and new information arises).

For advanced compressed air energy storage, we have used proponent proposed costs as the 2023 IASR does not cover these systems.

6.2.8 Non-network synchronous condensers

A non-network synchronous condenser is a synchronous condenser owned and operated by a third party which would enter into an agreement with Transgrid to provide system strength services.

These synchronous condensers were proposed as a new build solution, which means that the entire cost to commission and operate was accounted for in the PADR market modelling (same as for network synchronous condensers). These key costs including capex, FOM and VOM were all provided by the proponent.

60 https://www.snowyhydro.com.au/news/securing-the-future-of-critical-energy-transformation-resets/

61 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

7 Estimating option market benefits

Seven categories of market benefit under the RIT-T are considered material for this RIT-T, including the recently added 'changes in Australia's greenhouse gas emissions', and have been estimated as part of the PADR assessment. Wholesale market modelling has been used to estimate these categories of market benefits.

Competition benefits, option value and changes in ancillary service costs are not expected to be material for this RIT-T and so have not been estimated.

7.1 Expected market benefits from the portfolio options

For each scenario described in section 8.1, the RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible portfolio options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation and storage investment as well as unrelated future transmission investment (for example, that is required to connect REZs).

The specific categories of market benefit under the RIT-T that have been modelled as part of this PADR are (in order of the scale of net market benefits that each brings to our portfolio options):

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in Australia's greenhouse gas emissions;
- changes in involuntary load curtailment;
- changes in costs for other parties in the NEM;
- changes in voluntary load curtailment; and
- changes in network losses.

A wholesale market modelling approach similar to the approach used in the ISP has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment.[62]

While section 7.2 below provides further detail on the approach taken to estimating each of these market benefits, it is also discussed in greater detail in Baringa's market modelling report.

7.1.1 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible portfolio options result in different patterns of generation and storage dispatch across the NEM, compared to the base case. This is found to be the largest category of market benefit estimated across the portfolio options (noting that the avoided unserved energy estimates have been capped, as explained in section 7.1.3 below).

In the base case, existing synchronous machines are re-dispatched heavily to meet the growing system strength requirements. All four portfolio options (and sensitivities) see a considerable buildout of

[62] The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP(s) can provide reasons why this methodology is not relevant. See AER, *Regulatory Investment Test for Transmission*, August 2020, p. 8.

synchronous condensers and grid-forming batteries, which reduce the need for significant additional coal, gas and hydro re-dispatch relative to the base case and therefore result in net market benefits associated with avoided fossil fuel consumption.

7.1.2 Changes in Australia's greenhouse gas emissions

Following the change to the National Electricity Objective (NEO) in September 2023 to include changes in Australia's greenhouse gas emissions, and the subsequent change to the NER on 1 February 2024, TNSPs now need to include a new benefit category to cater for changes in emissions in RIT-T assessments (where material). This category has been found to be the second largest category of market benefit estimated for each of the portfolio options.

On the 28 March 2024, the Ministerial Council on Energy (MCE) published a statement about the interim value of greenhouse gas emissions reduction – this set out the methodology for how the Value of Emissions Reduction (VER) should be determined.[63] The AER also published draft guidance in March 2024 on valuing emissions reductions and stated that RIT-Ts should be undertaken using a consistent approach to that taken in the ISP, unless there is a strong reason not to do so, and included a table with the same annual VERs as those published by the AEMC.[64] Transgrid note that this additional AER guidance is binding due to the transitional provisions stipulated in the Act.[65]

Due to the timing of these developments, Transgrid have not been able to fully adopt the VERs as determined by the Energy Ministers. Specifically, the approach applied for the PADR analysis has been as follows:

- for the portfolio optimisation process (using PLEXOS Long-Term modelling) – the VER has been included within the portfolio formation process but not directly through the SRMC of assets. Instead, we have captured the additional emissions that come from the increased re-dispatch of existing assets for system strength purposes by using asset-specific constraints:
  - this process has valued each additional tonne of carbon emissions from the generation of electricity using the NSW Treasury recommended VER for all portfolio options and sensitivities[66] (with the exception of the VER sensitivity, which uses the Energy Ministers' VER values); and
- for the subsequent NPV assessment (using PLEXOS Short Term modelling) – the Energy Ministers published VER is used, ex-post, for all options and sensitivities (and, for the VER sensitivity, we have expanded this to investigate +/- 25% on the VER value consistent with the MCE guidance).[67] Applying VER ex-post means that emissions costs do not affect market dispatch decisions, but are incorporated in the costs and benefits assessment.

In light of needing to finalise the inputs for our market modelling before March 2024, Transgrid considers its approach is consistent with the September 2023 draft guidance of the AER, i.e., Transgrid have used a reputable VER and have conducted sensitivity analysis with a reasonable margin to understand the potential impact that specific values of emissions reduction may have in this RIT-T.[68] Transgrid also

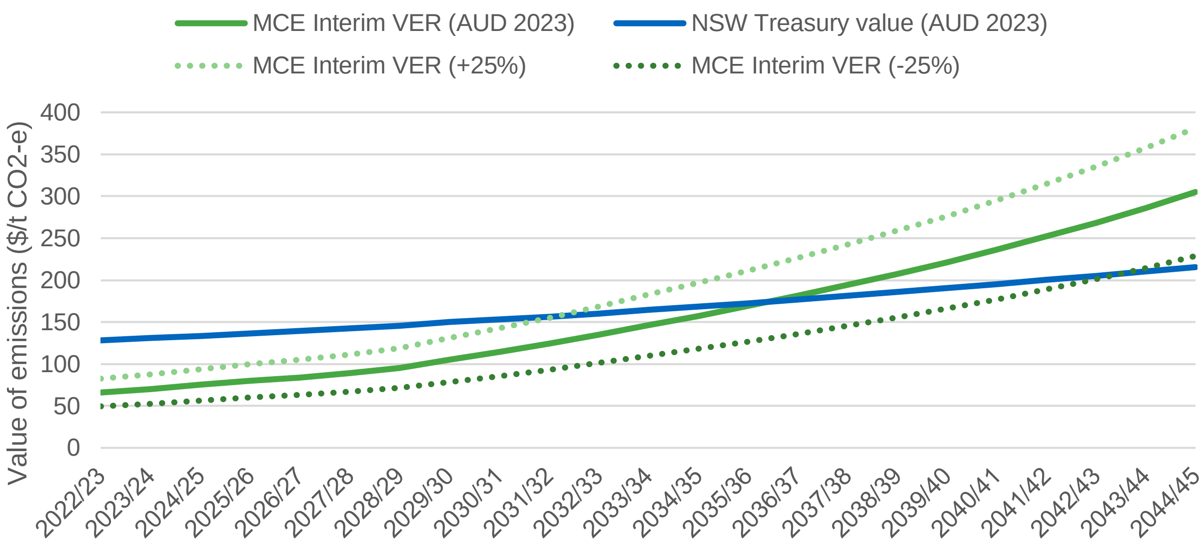
63 https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf
64 AER, *Valuing emissions reduction*, AER draft guidance, March 2024, p. 6.
65 AER, *AER guidance on amended National Energy Objectives Guidance Note*, September 2023, p. 8.
66 https://www.treasury.nsw.gov.au/sites/default/files/2023-03/20230302-technical-note-to-tpg23-08_carbon-value-to-use-for-cost-benefit-analysis.pdf
67 https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf
68 AER, *Amended National Energy Objectives (Emissions Reduction) – Guidance Note*, Explanatory Statement, September 2023, p. 9.

consider that the general approach taken to be consistent with how we understand AEMO are incorporating the benefits from changes in greenhouse gas emissions in its 2024 ISP.

Transgrid discussed its approach with the AER considering the timing of the developments above and we expect to update the approach taken for the PACR to align with the Energy Ministers' work and updated RIT-T Guidelines (if finalised).

The graph below presents a comparison of the two VERs used. While there is deviation between the two sources, results of the sensitivity analysis shows that there is almost no difference in the optimal portfolio of solutions (reinforcing that the difference in VER is not material).

Figure 7.1 – Comparison of the VER as recommended by NSW Treasury (2023) and Energy Ministers' MCE (2024)



7.1.3 Changes in involuntary load curtailment

As outlined in section 5.5, under the base case, where no action is taken to meet NSW's minimum and efficient level system strength requirements, there would be a significant deficit in system strength because of retiring coal generation and growing renewable connections.

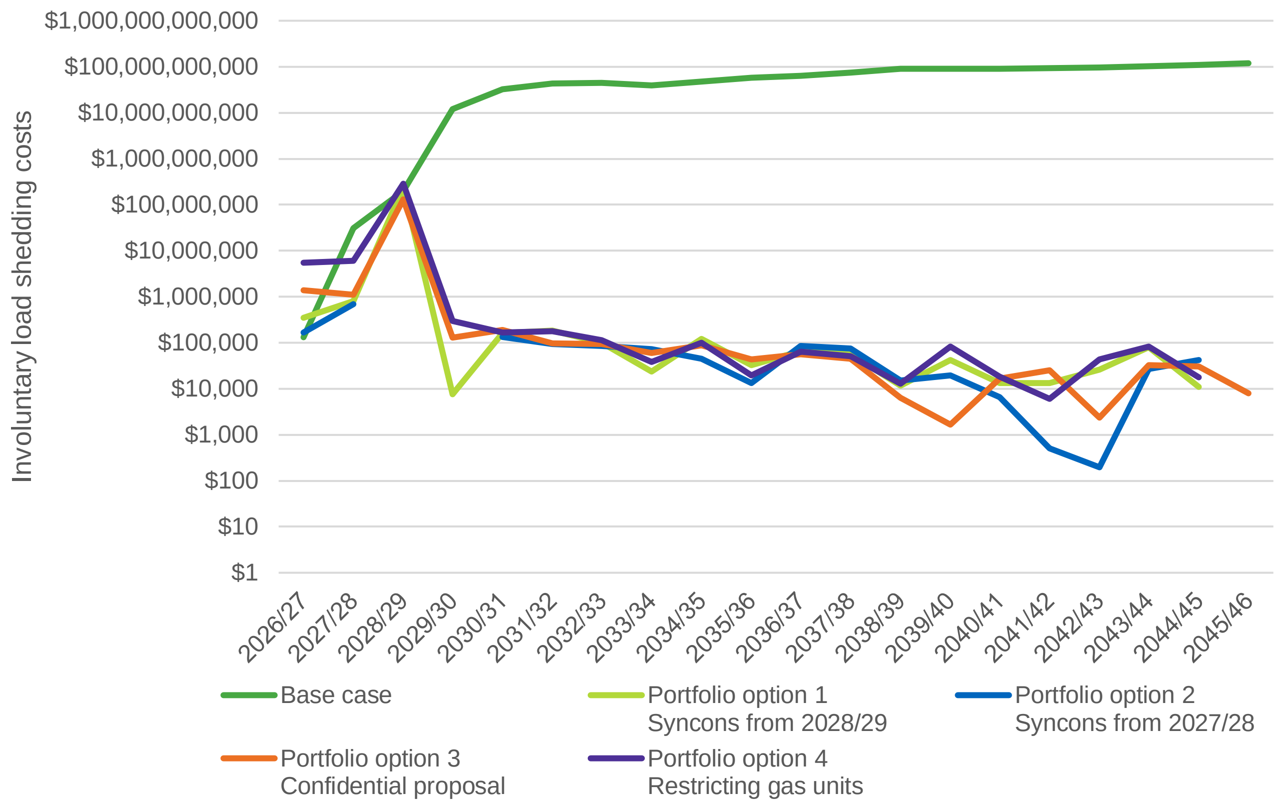
In this hypothetical future, it is expected that AEMO would direct existing synchronous generators to operate, or to constrain renewable generation (where possible) to maintain system security. If the efficient level of system strength is not met, the remaining renewable generation that is able to operate securely may be insufficient to meet system demand, which may lead to load shedding.

If the minimum level of system strength is not met, voltage control and protection systems may not operate correctly, leading to cascading failures in the transmission network and, in the worst case, widespread and extensive power outages.

As outlined in section 5.5, Transgrid have not included in the assessment the substantial unserved energy that would be expected to arise under the base case if no action is taken (e.g., the unserved energy associated with catastrophic failure of not meeting the minimum level, or significant breaches in the efficient level) since exactly how it would unfold is not known and all portfolio options are explicitly designed to avoid it in the same way (i.e., it is not material to the RIT-T assessment).

Transgrid presents a summary of involuntary load shedding costs in undiscounted 2023/24 dollars under the base case relative to the option cases in Figure 7.2 below. This figure shows the magnitude of involuntary load shedding costs under the base case, which dwarfs that under all option cases (which is why it was capped).

Figure 7.2 – Value of involuntary load curtailment under base case and portfolio options (undiscounted $2023/24)



Note: the value of involuntary load curtailment is zero for portfolio option 2 in 2027/28 and 2028/29, which cannot be plotted correctly on the logarithmic chart above.

As such, while all portfolio options are designed to avoid these outcomes under the base case (and so all avoid substantial amount of unserved energy), Transgrid have only valued the *differences* in avoided unserved energy across the portfolio options. Transgrid explicitly removed all avoided unserved energy common to each of the options, since including it would not assist with identifying the preferred option overall and would make the comparison of how the portfolio options differ in term of estimated net benefits difficult. This is because the substantial avoided unserved energy common to each of the options would swamp the other benefit sources. Transgrid considers this is consistent with the approach adopted in other RITs, the Energy Networks Australia RIT-T Handbook and advice provided to the AER.[69]

The market benefit of 'changes in involuntary load curtailment' involves quantifying the impact of changes in the estimated involuntary load shedding associated with the implementation of each portfolio option. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period as a result in violations in minimum or efficient-level requirements, and then applies a

[69] Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.

Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted the AER's most recent assumptions for the VCR for the purposes of this assessment.

7.1.4 Changes in costs for other parties in the NEM

This category of market benefits is expected where the operational patterns of assets within portfolio options change in response to meeting system strength constraints, relative to the base case.

This market benefit class captures the differences in Fixed Operation & Maintenance costs (FO&M), Variable Operating & Maintenance Costs (VO&M) and Generator Start and Stop costs. It has been found to be material when considering the interaction of existing synchronous machines re-dispatched for system strength purposes and the build of dedicated system strength assets.

Variations in the operational commencement dates of newbuild system strength solutions across different portfolio options are found to be material in driving this market benefits class.

7.1.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a portfolio option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This category of market benefit has not been found to be material in the assessment, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant.

7.1.6 Changes in network losses

The time-sequential market modelling has considered the change in network losses that may be expected to occur as a result of the implementation of each of the portfolio options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the options is not considered material for the portfolio options considered in this PADR, since losses from synchronous condensers or generators running in synchronous condenser mode is very minor compared to overall network losses. The main factor that influences losses is the amount of current flowing through transmission lines, which depends on generation dispatch, rather than the fault level.

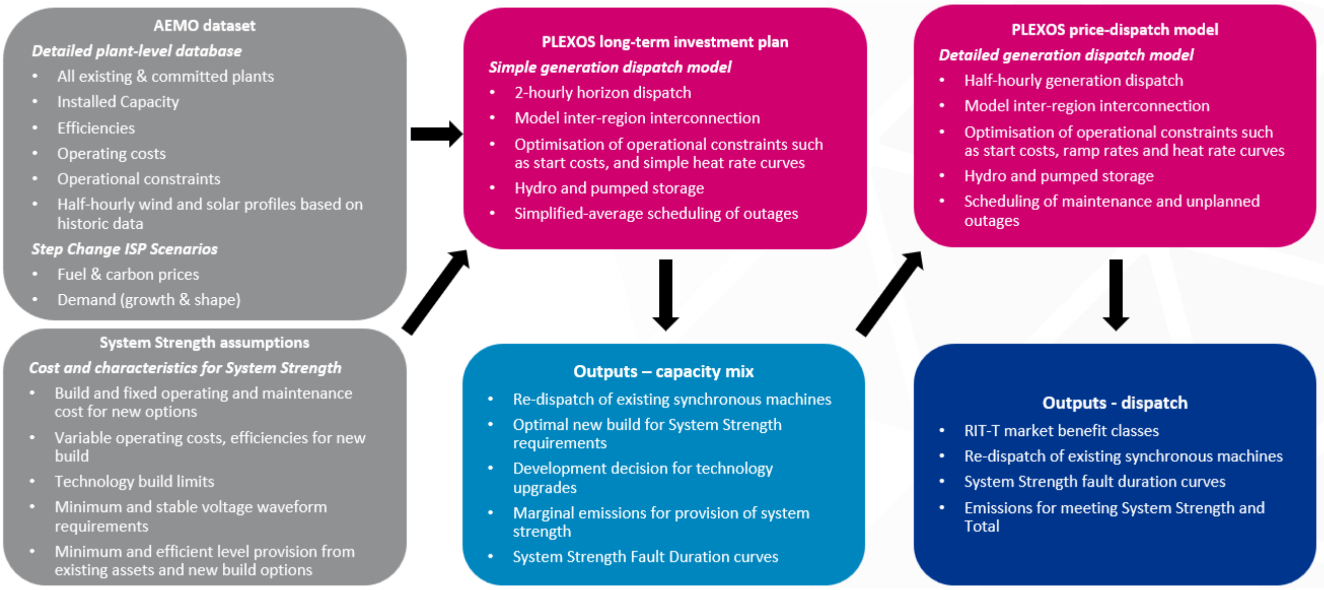
7.2 Market modelling has been used to estimate the wholesale market benefits

Transgrid engaged Baringa to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the portfolio options. Baringa has integrated system strength constraints into market modelling software (PLEXOS) to calculate the categories of wholesale market benefits associated with the portfolio options.

This RIT-T analysis utilises a Baringa constructed PLEXOS model to form optimal portfolios of system strength solutions. Mixed Integer programming techniques are used to compute a least cost, whole-of-NEM solution that progressively solves both the capacity expansion and unit commitment problems with respect to meeting Transgrid's system strength requirements.

Baringa and Transgrid have undertaken detailed power system simulations to evaluate the performance of options portfolios and validate their credibility to provide adequate system strength across the modelled horizon. The portfolio options are configured into a dispatch model, which closely follows the operation of the NEM to estimate market benefit classes and ensure accurate dispatch of available assets.

Figure 7.3 – Summary of the market modelling processes undertaken



The modelling process uses the same market modelling software (PLEXOS) as AEMO and input assumptions aligned with AEMO's Draft 2024 ISP Step change, based on AEMO's latest 2023 IASR. Where material market updates have emerged since the IASR and draft ISP, these have been incorporated. Key examples of such updates are an updated NSW coal closure schedule, and incorporation of the New South Wales Network Infrastructure Strategy (NIS).

Further details on the inputs and methodologies applied by Baringa for estimating the market benefits of each portfolio option can be found in separate market modelling methodology report.

7.3 Competition benefits, option value and changes in ancillary service costs are not expected to be material

As the portfolio options considered in this PADR do not address network constraints between competing generators, and all credible options are expected to meet the system strength requirements, competition benefits are not expected to be material for this RIT-T assessment.

While each portfolio option is found to involve a number of flexible/modular elements, 'option value' is not considered material for this RIT-T on account of only one scenario being considered relevant for the assessment (as outlined in section 8.1). Moreover, as outlined in section 8.1, we consider that each portfolio option exhibits the same approximate level of flexibility and so do not consider there to exist materially different levels of option value across the portfolios.

While the cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity from the options, 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 (because the quantity of grid-forming BESS is relatively similar across all options portfolio). FCAS costs are relatively small compared to total market costs and the market is relatively shallow.

There is unlikely to be material changes between portfolio options to the costs of Network Support and Control Ancillary Services (NSCAS), or System Restart Ancillary Services (SRAS) because of the options being considered.

7.4 General cost benefit analysis parameters adopted

The PADR analysis considers a 20-year assessment period from 2025/26 to 2044/45. This period was selected considering the period for which forecasts are available and the size, complexity and expected asset lives of the options and provides a reasonable indication of the costs and benefits over a long outlook period. It also reflects a standard wholesale market modelling period of 20 years from when the new obligations commence in 2025/26.

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 will be calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life.

A real, pre-tax discount rate of 7% has been adopted as the central assumption for the NPV analysis presented in this PACR, consistent with AEMO's latest IASR.[70] The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. Transgrid have therefore tested the sensitivity of the results to a lower bound discount rate of 3.63%.[71] Transgrid have also adopted an upper bound discount rate of 10.5% (i.e., the upper bound in the latest IASR).[70]

[70] AEMO, 2023 Inputs, Assumptions and Scenarios Report | Final report, July 2023, p 123.

[71] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Transgrid) as of the date of this analysis, see: AER, *TasNetworks – 2024-29 – Final decision – PTRM*, April 2024, WACC sheet.

8 Ensuring the robustness of the analysis

We have assessed each portfolio option against the ISP Step Change scenario consistent with how our system strength obligations are set by AEMO.

We have used the assumptions in the final 2023 IASR for assessments undertaken as part of this PADR (i.e., both the portfolio option formation process and the wholesale market modelling).

We have undertaken a number of sensitivity tests to confirm the robustness of the RIT-T assessment and to inform the identification of re-opening triggers.

8.1 The assessment considers the ISP Step Change scenario

Transgrid have assessed each portfolio option against the ISP Step Change scenario consistent with how our system strength obligations are set by AEMO. The Step Change scenario is summarised by AEMO as achieving 'a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels'.[72]

The other two ISP scenarios (i.e., the Progressive Change and Green Energy Exports scenarios) have not been used in the analysis. This is because Transgrid does not consider them to be relevant in light of our current obligations in which our stable voltage waveform requirements driven by AEMO's IBR forecasts, which have been determined by AEMO using the Step Change scenario.

If the NEM development and policy landscape changes and we were, for example, in a state of the world that looked more like the Green Energy Exports scenario then the system strength obligation on Transgrid would not automatically change. Instead, the obligation would be updated by AEMO in time and would then only apply to Transgrid via the next binding three-year period.[73]

In this case, a new RIT-T may be necessary to decide how best to procure the additional system strength associated with the change in obligation. However, this RIT-T process has already sought to consider changes in key underlying assumptions to identify the impact on what is considered optimal to procure (e.g., reductions in IBR forecasts that Transgrid is required to remediate), and this will be further refined for the PACR. This may mean it will not be necessary to redo the RIT-T, if our obligations change in a way that is similar to what has already been assessed as part of this RIT-T.

Transgrid considers that using the Step Change scenario only is a key point of difference for this RIT-T compared to other RIT-Ts, such as those driven by uncertain load growth. Specifically, the obligations for these other RIT-Ts are fixed in the NER on a general basis (i.e., are not ISP scenario specific) and do not require the additional step of AEMO determining the obligation.

Further, Transgrid considers that assessing all three ISP scenarios as part of this RIT-T would require mimicking what AEMO would do in determining Transgrid's updated obligations for the other two scenarios. This would require a substantive modelling effort which is not considered proportionate for this RIT-T in light of Transgrid's obligations being set by reference to the Step Change scenario (and the future process, outlined above, if things change materially from current expectations).

72 AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, p. 15.

73 Specifically, Transgrid's obligation to meet the standard under Schedule 5.1.14 from 2 December 2025 is framed around the 'system strength standard specification' (which defines the binding requirement as the forecast requirements determined three years prior.

Table 8.1 below summarises the specific key variables that influence the net benefits of the options under the Step Change scenario.

Table 8.1 – PADR modelled scenario key drivers input parameters

Key input parameters	Source
Underlying Consumption	Final 2022 NEM Electricity Statement of Opportunities (Step Change scenario)
Demand Side Participation (DSP)	AEMO IASR 2023 (Step Change scenario)
Rooftop PV	AEMO IASR 2023 (Step Change scenario)
Victorian Renewable Energy Target (VRET)	AEMO IASR 2023. 95% minimum VRE of state-wide generation by 2034/35. IASR Interim targets and IASR interpolation of target also modelled to this point
Queensland Renewable Energy Target (QRET)	AEMO IASR 2023. 80% minimum VRE share of underlying consumption by 2034/35. IASR Interim targets also modelled to this point
Tasmanian Renewable Energy Target (TRET)	AEMO IASR 2023. 21,000GWh of renewable generation by 2039/40. Interim target and IASR interpolation of target followed to this point.
Resource Limits	AEMO IASR 2023
Group REZ limits	AEMO IASR 2023
VIC Offshore Wind	AEMO IASR 2023. 9GW of Victorian offshore wind capacity by 2039/40. IASR Interim targets also modelled to this point.
VIC Energy Storage Target	AEMO IASR 2023. 2.6GW by 2030 and 6.3GW of energy storage systems by 2034/35.
NSW Energy Infrastructure Roadmap (EIR) Generation	AEMO IASR 2023. 33,600GWh per year by 2029/30.
NSW Energy Infrastructure Roadmap (EIR) Storage	AEMO IASR 2023. 2000MW of eligible large-scale storage by 2029/30.
NSW Firming Constraint	AEMO Draft ISP 2024. 930MW of eligible installed capacity by 2025/26.
Transmission development pathway	Final 2022 ISP Optimal Development Pathway (ODP) with updates to align NSW flow path augmentations with the NIS Central Scenario and QLD with the SuperGrid Infrastructure blueprint.
Network Representation	AEMO IASR 2023
VER	Portfolio Formation non VER Sensitivity: Emissions analysis using NSW Cost of Carbon Emissions Portfolio Formation VER Sensitivity: Emissions analysis using AER Draft Guidance Valuing Emissions Reduction[74] Market Benefits Analysis: Emissions Analysis using AER Draft Guidance Valuing Emissions Reduction
Fixed Date Asset Retirement - NSW Coal	AEMO Draft ISP 2024 (Step Change scenario)
Fixed Date Asset Retirement - non-NSW Coal	VIC: AEMO Final ISP 2022 (Step Change scenario) QLD: SuperGrid Infrastructure blueprint.
Fixed Date Asset Retirement - Gas	AEMO IASR 2023
Fixed Date non-thermal Asset Retirement	AEMO IASR 2023
Snowy 2.0 commissioning date	December 2028. October 2023 NEM Gen Info

[74] AER, *Valuing emissions reduction*, AER draft guidance, March 2024.

Key input parameters	Source
New Entrant Build Limits	AEMO IASR 2023
Generator Energy Limits	AEMO IASR 2023
Capital Costs	AEMO IASR 2023 (Step Change scenario)
Weighted average cost of capital (WACC)	AEMO IASR 2023 (Central scenario)
New Entrant Generators	AEMO IASR 2023
Renewable Energy Zone Representation	AEMO IASR 2023
Capacity Factors	AEMO IASR 2023
Coal Fuel Cost	AEMO IASR 2023 (Step Change scenario)
Gas Fuel Cost	AEMO IASR 2023 (Step Change scenario)
Technical Parameters of Existing Generation & Storage	AEMO IASR 2023
Inertia Constraint	Not modelled

8.2 Sensitivity analysis

In addition to the core modelling, Transgrid have also considered the robustness of both the outcome of the portfolio optimisation modelling and the robustness of the ranking of portfolios under the NPV assessment. This was achieved through undertaking a range of sensitivity tests.

Specifically, Transgrid have undertaken:

- Sensitivity analysis regarding the RIT-T NPV assessment (see section 9.6):
  - 25% higher and lower VER values, (i.e., consistent with the MCE guidance);[75]
  - 30% higher and lower VCR values (i.e., consistent with the AER's state level of confidence);[76]
  - 25% higher and lower assumed synchronous condenser costs (both capital and operating costs);
  - 25% higher and lower grid-forming BESS upgrade costs; and
  - lower and higher commercial discount rates (as discussed in section 7.4).
- Sensitivity analysis regarding the optimal portfolio composition (see section 9.7):
  - a range of 'self-remediation' sensitivities for both NSW REZs and modelled BESS, to test the implications of a reduction in the amount of system strength we may need to procure;
  - where grid-forming BESS are able to provide more 'stable voltage waveform' support than Transgrid currently expects (based on our current PSCAD modelling);
  - alternate VERs (consistent with those determined by Energy Ministers and published by the AER in March 2024[77]); and
  - assuming a one-year delay to contracting with all grid-forming BESS (or conversions to become grid-forming), given they represent a relatively novel solution and have a range of timing

[75] https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf
[76] AER, *Widespread and long duration outages – values of customer reliability*, Final conclusions, September 2020, p. 8.
[77] AER, *Valuing emissions reduction*, AER draft guidance, March 2024, p. 4.

uncertainties in particular where NER 5.3.9 generator modifications are required, and a hydro unit that has proposed to upgrade their plant to enable it to operate in both generation and synchronous condenser modes.

Transgrid have also estimated the ‘boundary value’ for key variables (e.g., assumed capital costs) beyond which the outcome of the analysis would change. As there are inter-dependencies between many of these variables, the boundary values are indicative only and assume that other variables do not change. These boundary values, along with other select sensitivities, have been used to inform the re-opening triggers proposed in section 9.8 of this PADR.

Transgrid intend to investigate a range of other sensitivities as part of the PACR assessment, including Eraring’s extension and possible changes to the assumed retirement date of other NSW coal generators (compared to what is projected in AEMO’s 2024 ISP).

For example, as mentioned in section 4.2, the PACR is expected to include testing the sensitivity of the optimal portfolio option to differences in the individual components, including whether increasing the size/quantum of the grid-forming BESS in the optimal portfolio materially impacts the net market benefits expected from the portfolio option and/or changes its ranking compared to the second ranked portfolio.

9 Net present value analysis

The most credible portfolio option at this point in time (portfolio option 1) is found to deliver at least $11.3 billion in net benefits (in present value terms).[78]

Besides avoiding substantial unserved energy, this is driven primarily by significant avoided generator fuel costs and lower emissions with portfolio option 1 in place, compared to the base case. Both these sources of benefit stem from a reduced need for the re-dispatch of existing synchronous machines for system strength due to the introduction of dedicated system strength assets such as synchronous condensers and grid-forming BESS.

The PADR analysis also finds that:

- If the delivery of synchronous condensers can be accelerated by one year to 2027/28, the expected net market benefits increase by approximately $269 million (in present value terms).
  - This is driven primarily by the avoidance of significant levels of unserved energy and generator fuel costs in 2027/28.
- If the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West is assumed to be technically feasible, the expected net market benefits increase by approximately $149 million (in present value terms), in comparison to portfolio option 1.
  - Similar to the accelerated synchronous condenser case, this is driven by the confidential proposal avoiding significant levels of unserved energy and generator fuel costs in 2027/28, compared to portfolio option 1.
- If the number of gas units assumed to be contracted with is restricted, the expected net market benefits decrease by approximately $4 million (in present value terms), in comparison to portfolio option 1.
  - This is driven mainly by additional avoided fuel consumption by generators and greenhouse gas emissions (compared to portfolio option 1).

Sensitivity testing finds that if the future unfolds in a number of alternate ways to what has been assumed in the core portfolio options (i.e. when the underlying need itself changes), then the number of synchronous condensers required is the part of the portfolio that changes the most. The sensitivity testing also finds that the ranking of the portfolio options is not expected to be affected by a range of other underlying assumptions changing (such as discount rates), or by cost increases of synchronous condensers or BESS.

9.1 Summary of the results

Portfolio option 1 (where the earliest commissioning year for synchronous condensers is assumed to be 2028/29 and the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West is not assumed to be technically feasible) is found to generate substantial estimated net benefits over the assessment period – approximately $11.3 billion in present value terms.

The analysis also finds that:

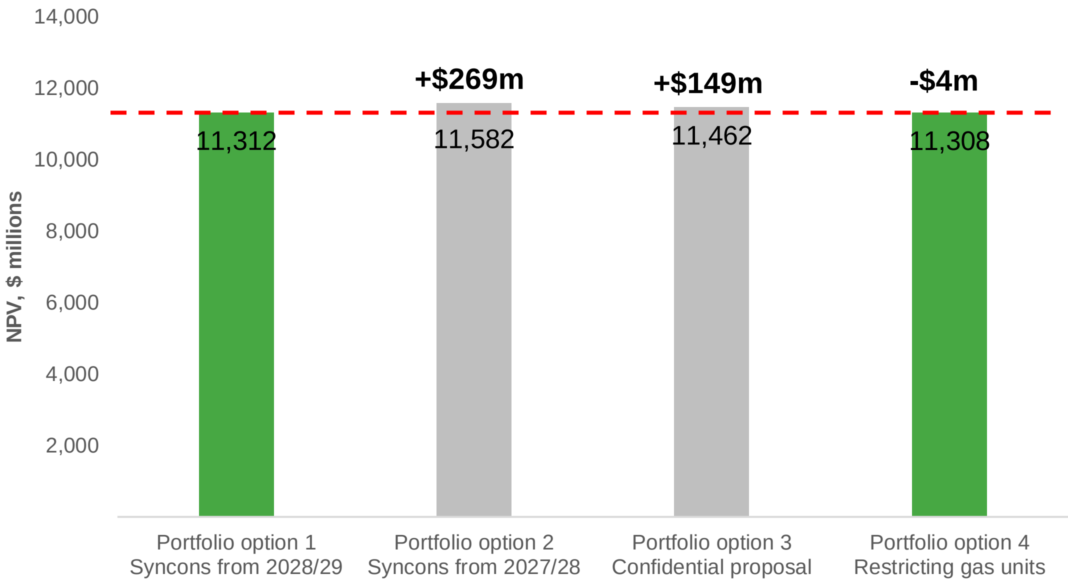
- if the delivery of synchronous condensers can be accelerated by one year (i.e., under portfolio option 2), the expected net market benefits increase by approximately $269 million (in present value terms);

[78] Please note that 'at least' is used here, and throughout the report when discussing the headline net market benefits, on account of the approach taken to remove the avoided unserved energy that is common to all option portfolios from the assessment since it does not assist with ranking the options (as discussed in section 5.5). If this unserved energy is added to the analysis, the expected net benefit of portfolio option 1 (and all option portfolios) would be significantly greater.

- if the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West is assumed to be technically feasible (i.e., under portfolio option 3), the expected net market benefits increase by approximately $149 million (in present value terms); and
- if the number of gas units assumed to be contracted with is restricted, the expected net market benefits decrease by approximately $4 million (in present value terms).

The figure below summarises the headline NPV results for each of the portfolio options, as well as providing an explicit comparison to portfolio option 1 for portfolio options 2-4.

Figure 9.1 – Headline NPV results for each of the portfolio options. Green indicates currently credible portfolio option; grey indicates a portfolio option where investigation will continue over the course of the RIT-T to see whether credibility can be confirmed.



The following three sections discuss the results for each portfolio option in-turn.

9.2 Portfolio option 1 – Synchronous condensers available from 2028/29

Portfolio option 1 represents what we consider to be the most realistic set of assumptions right now regarding the timing of when synchronous condensers could be available, as such, it is considered the most credible option at this point in time.

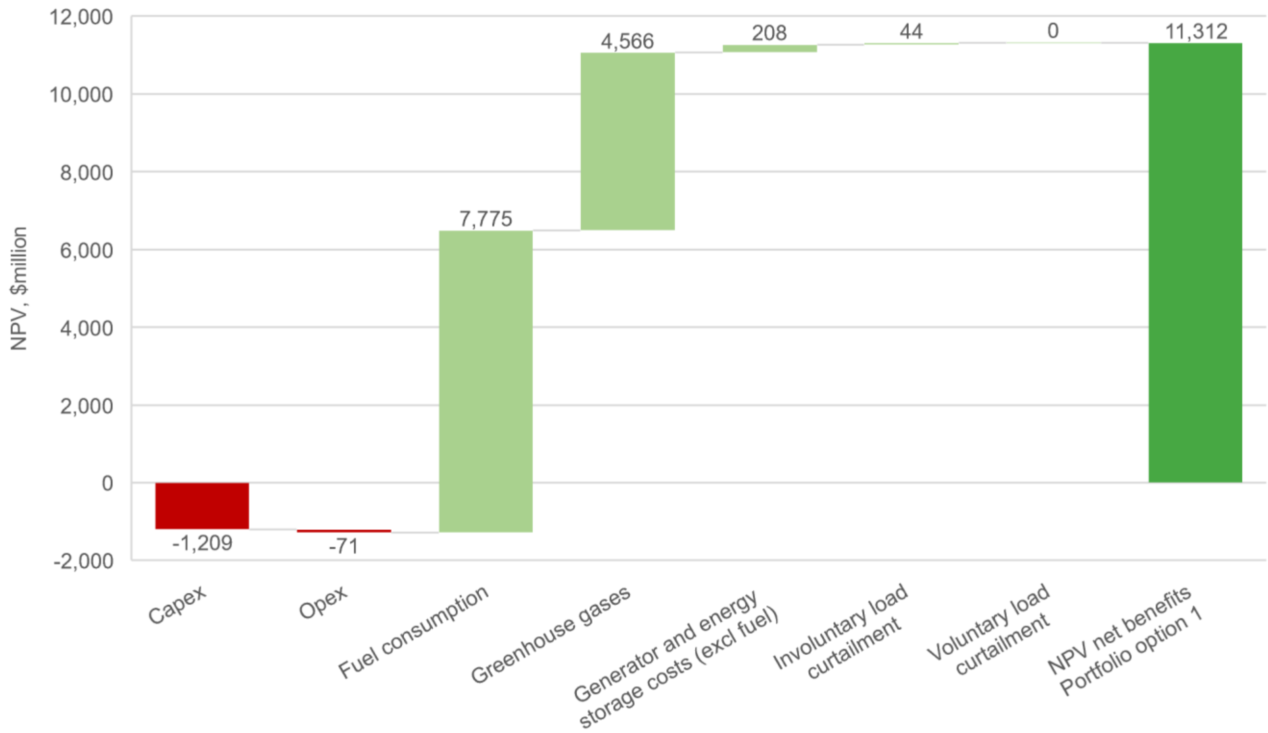
Portfolio option 1 is made-up of:

- fourteen synchronous condensers by 2032/33, with eight in place in 2028/29 (i.e., the earliest they can be commissioned under the portfolio option);
- modifications to synchronous hydro generators and the addition of clutches to the Broken Hill compressed air energy storage facility by 2027/28, contributing in total over 550 MW of system strength services, beginning in 2026/27;
- re-dispatching a range of existing hydro generators to ensure they can switch on or operate in synchronous condenser mode where necessary to fill gaps in system strength, beginning in 2026/27, as well as a smaller amount of gas and black coal units also being re-dispatched; and
- 4.8 GW of new build grid-forming BESS by 2032/33, beginning in 2025/26.

While this option is currently considered the most credible of the four assessed, there are gaps in system strength that cannot be filled in 2027/28 under this option, which presents risks to outcomes for the power system and end consumers (including through expected unserved energy). These gaps can be filled in portfolio option 2 and reduced (but not closed) in portfolio option 3.

Overall, portfolio option 1 is found to deliver at least $11.3 billion in net benefits (in present value terms) over the assessment period. This result is driven primarily by significant avoided generator fuel costs and lower emissions with the portfolio option in place, compared to the base case.

Figure 9.2 – Composition of the estimated net market benefits for portfolio option 1 (NPV, $millions)[79]



Both the avoided fuel costs and lower emissions of portfolio option 1 relative to the base case stem from a reduced need for the re-dispatch of synchronous machines. This is primarily due to the introduction of dedicated system strength assets such as synchronous condensers and grid-forming BESS reducing the need to dispatch such assets for system strength reasons.

9.3 Portfolio option 2 – Synchronous condenser delivery accelerated to 2027/28

Portfolio option 2 has been included to investigate whether there would be significantly greater expected net market benefits if the procurement of synchronous condensers could be accelerated by one year, i.e., synchronous condensers could be commissioned in 2027/28, rather than 2028/29 as assumed for portfolio option 1. To enable this, Transgrid would need to place orders for synchronous condensers prior to the RIT-T being complete and the AER's approval of a CPA.

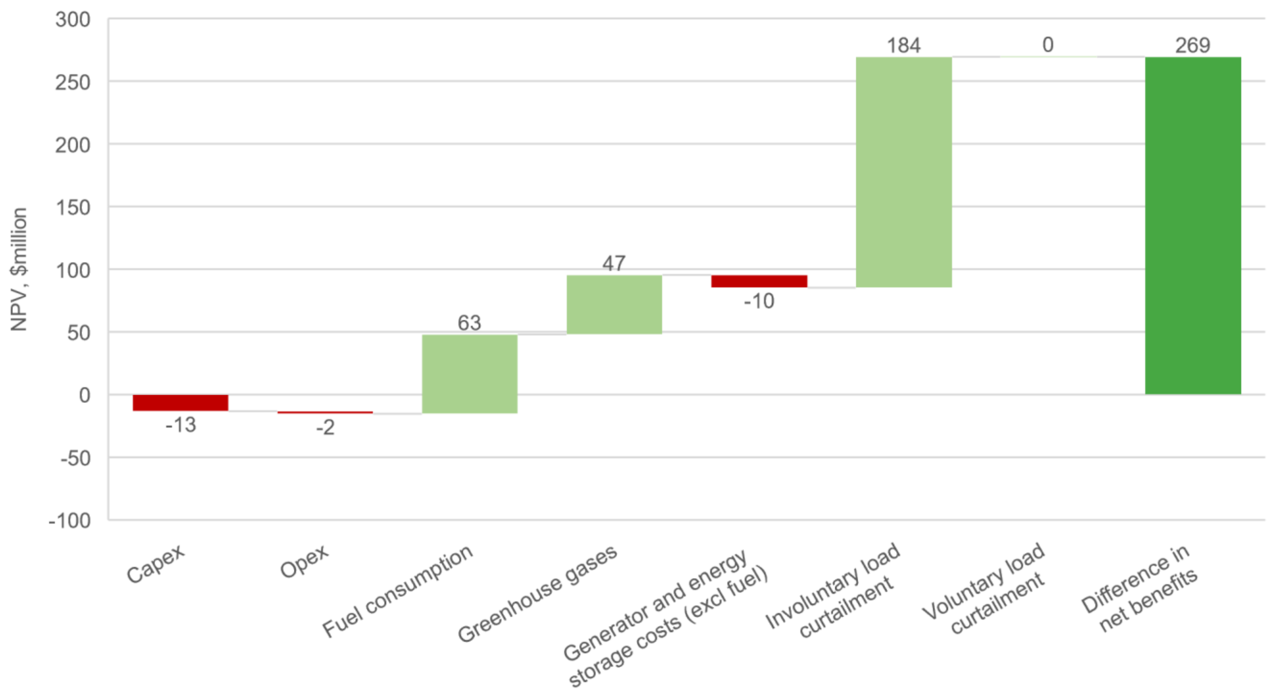
79 Please note that all net market benefits in this report, including their breakdown (as shown in these types of charts, are shown relative to the base case.

Changing this assumption in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio:

- brings forward five synchronous condensers one year, from 2028/29 to 2027/28;
- results in effectively the same re-dispatch as portfolio option 1 (i.e., almost all hydro generators, with a smaller amount of gas and black coal units also being re-dispatched); and
- effectively requires the same amount of grid-forming BESS (with slight timing differences).

Under this portfolio option, the expected net market benefits increase by approximately $269 million (in present value terms), compared to under portfolio option 1. This increase is driven primarily by the earlier synchronous condensers avoiding significant levels of unserved energy, generator fuel costs and greenhouse gases in 2027/28, compared to portfolio option 1 (which assumes synchronous condensers can be commissioned in 2028/29 at the earliest).

Figure 9.3 – Key changes in the composition of the estimated net market benefits for portfolio option 2, compared to portfolio option 1



The avoided fuel costs and lower emissions benefits of portfolio option 2 relative to portfolio option 1 primarily stem from the reduced re-dispatch of synchronous machines in 2027/28. Portfolio option 2 assumes synchronous condensers can be commissioned a year earlier (in 2027/28) and so reduce the need for system strength initiated re-dispatch in this year.

In addition to increased market benefits for consumers and a reduction in system strength gaps, accelerating the procurement of synchronous condensers (as per portfolio option 2) also provides insurance against the risk of further synchronous condenser supply chain delays, early coal retirements and reduces the dependence on higher emissions synchronous machines for system strength. Across all portfolio options and portfolio option sensitivities, between eight to fourteen synchronous condensers are required by 2032/33 – Transgrid believe that if feasible, the accelerated procurement of five synchronous condensers represents a 'no regret' path forward.

9.4 Portfolio option 3 – Confidential proposal technically feasible (and synchronous condensers available in 2028/29)

Portfolio option 3 differs from portfolio option 1 in that it assumes that a confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West nodes is technically feasible. A detailed feasibility study has not been undertaken and there is a reasonable likelihood that this solution may not ultimately be feasible. A successful feasibility study would be required prior to PACR market modelling to consider it as a credible solution.

Changing this assumption in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio:

- requires four less synchronous condensers by 2032/33 and, importantly, no synchronous condensers at Sydney West and Newcastle – it also defers one of the two synchronous condensers at Tamworth in 2028/29 two years (to 2030/31), as well as two synchronous condensers in the New England REZ (in 2030/31 and 2031/32) and one synchronous condenser in CWO REZ (in 2029/30) beyond 2032/33;
- continues to re-dispatch a range of existing hydro generators to ensure they can switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength (as well as a smaller amount of gas and black coal units also being re-dispatched); and
- effectively requires the same amount of new build grid-forming BESS (though with 400 – 600 MW extra procured between 2026/27 and 2028/29) in addition to the confidential proposal.

Under this portfolio option, the expected net market benefits increase by approximately $149 million (in present value terms), compared to under portfolio option 1. As with portfolio option 2, the additional avoided unserved energy compared to portfolio option 1 comes from 2027/28.

Due to the confidentiality requested by the proponent of the confidential proposal, Transgrid is only able to present the net market benefits of portfolio option 3 (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

9.5 Portfolio option 4 – Restricting the number of gas units (and synchronous condensers available in 2028/29)

Portfolio option 4 explores how varying the number of gas units we contract would change the portfolio of solutions and overall net market benefits. The purpose of this scenario is to see if a reduced portfolio of gas units would have total benefits within the margin of error of portfolio option 1 and, if so, it may affect how Transgrid contracts with these generators to drive a more competitive outcome. While portfolio option 1 places no constraint on the number of gas units Transgrid can contract with, portfolio option 4 limits the number of gas units contracted with.

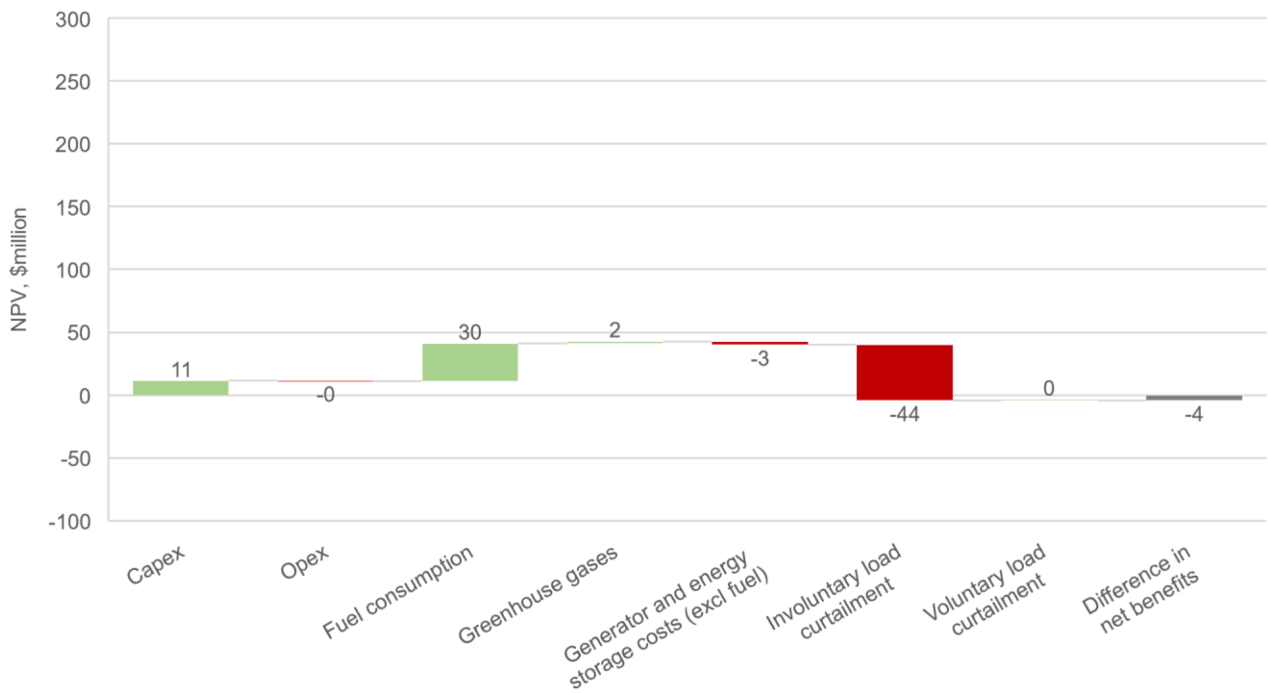
Changing this assumption in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio:

- brings forward two synchronous condensers by one year, from 2029/30 to 2028/29 and adjusts the timing of two other synchronous condensers between 2031/32 and 2034/35. The same number of synchronous condensers is required over the modelling period (26 in total);

- continues to re-dispatch a range of existing hydro generators to ensure they can switch on or operate in synchronous condensers mode where necessary to fill gaps in system strength (as well as a smaller amount of gas and black coal units also re-dispatched) – however, there is less gas re-dispatched at the start of the period than under portfolio option 1; and
- effectively requires the same amount of new build grid-forming BESS (with slight differences in timing).

Under this portfolio option, the expected net market benefits decrease by approximately $4 million (in present value terms), compared to under portfolio option 1. The decrease in net market benefits driven primarily by involuntary load curtailment increasing.

Figure 9.4 - Key changes in the composition of the estimated net market benefits for portfolio option 4, compared to portfolio option 1



The trade-off between greater avoided fuel costs and higher levels of expected unserved energy for portfolio option 4, is a consequence of its construction. Specifically, by restricting the ability of certain gas plants to enter into contracts with Transgrid for system strength, the same plants are not re-dispatched for system strength reasons under portfolio option 4 as they are in portfolio option 1. This allows more expensive gas plant to be avoided, but also results in greater gaps in system strength and consequently higher involuntary load shedding.

9.6 Sensitivity analysis

Transgrid have tested the robustness of the previous NPV analysis by changing a number of key variables. Specifically, these tests investigate whether the ranking of the options changes (and whether the preferred portfolio option changes) under these alternate key assumptions.

Transgrid have tested the impact on the portfolio rankings of:

- 25% higher and lower VER values, (i.e., consistent with the MCE guidance);[80]
- 30% higher and lower VCR values (i.e., consistent with the AER's state level of confidence);[81]
- 25% higher and lower assumed synchronous condenser costs (both capital and operating costs);
- 25% higher and lower grid-forming BESS upgrade costs; and
- lower and higher commercial discount rates (as discussed in section 7.4).

Importantly, the key findings of the core PADR analysis outlined above are found to be robust to changes under these sensitivities. Specifically, under all sensitivities investigated:

- the most credible portfolio option at this point in time (portfolio option 1) is found to deliver significant net benefits;
- if the delivery of synchronous condensers can be accelerated by one year, the expected net market benefits increase (i.e., portfolio option 2 is always ranked ahead of portfolio option 1);
- if the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West is assumed to be technically feasible, the expected net market benefits increase (i.e., portfolio option 3 is always ranked ahead of portfolio option 1); and
- if we restrict the number of gas units assumed to be contracted with, the expected net market benefits decrease (i.e., portfolio option 4 is always ranked below portfolio option 1 – with the exception of if we assume VCR values are at least 10% lower than the AER values[82]).

Appendix D presents the results of each of these sensitivities.

In addition, Transgrid do not find any realistic boundary values under any of the sensitivities investigated that would change the key findings of the core assessment. The boundary values, where they exist, are summarised in the table below.

Table 9.1 – Summary of the boundary assessments undertaken in this PADR

Key findings of this PADR	VER	VCR	Synchronous condenser costs	BESS upgrade costs	Discount rate
Portfolio option 1 having significant net benefits[83]	N/A	N/A	1176%	3763%	82.71%
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	N/A	N/A	1116%	N/A	97.31%
The confidential proposal to provide system strength services increasing the expected net benefits	N/A	N/A	-62%	1070%	2.37%
Restricting the number of gas units decreases the estimated net benefits	240%	-10%	N/A	31%	12.17%

80 https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf

81 AER, *Widespread and long duration outages – values of customer reliability*, Final conclusions, September 2020, p. 8.

82 If we assume VCR values that are approximately 10% lower than the AER values, portfolio option 4 is ranked equally with portfolio option 1, i.e., they have the same estimated net market benefits. At this stage, this is not considered a material boundary value and we note that, if VCR values are assumed to be 30% lower than the AER values (i.e., consistent with the lower confidence level quoted by the AER), portfolio option 4 is only preferred over portfolio option 1 by approximately $9 million (in present value terms) – as shown in Appendix D. On balance, and considering the other sensitivities and boundary values, we consider the finding that, if we restrict the number of gas units assumed to be contracted with, the expected net market benefits decrease (i.e., portfolio option 4 is ranked below portfolio option 1) to be robust.

83 We note that this boundary test is based on the capped USE values and, if this USE was included, the boundaries would be even more unrealistic.

9.7 Additional testing of the effects of changes that could emerge in the future

In addition to the general NPV sensitivity tests discussed above, Transgrid have also investigated how the composition of the most credible portfolio option (portfolio option 1) changes under a range of key alternate assumptions, which each reflect changes we consider could happen in the near future.

Specifically, Transgrid have tested, via the portfolio optimisation process, how portfolio option 1 would change if the following are assumed:

- a range of 'self-remediation' sensitivities for both NSW REZs and modelled BESS (which are assumed to be grid-following under the base case as part of the core assessment above) to test the implications of a reduction in the amount of system strength we actually need to procure;
- grid-forming BESS being able to provide more 'stable voltage waveform' support than Transgrid currently expects;
- alternate VERs (consistent with those determined by Energy Ministers and published by the AER in March 2024[84]); and
- assuming a one-year delay to contracting with all grid-forming BESS (or conversions to become grid-forming), given they represent a relatively novel solution and have a range of timing uncertainties, and a hydro unit that has proposed to upgrade their plant to enable it to operate in both generation and synchronous condenser modes.

These sensitivities have informed our proposed re-opening triggers (discussed in section 9.8 below). Specifically, these assessments help demonstrate the change in the preferred portfolio option that would be consistent with the RIT-T, if a re-opening trigger occurs, without needing to redo the RIT-T assessment.

For the PACR, assuming there is more than one credible portfolio option, we intend to do a more comprehensive sensitivity exercise across multiple portfolio options, to demonstrate that the ranking of the options would not change if these re-opening triggers occurred.

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

9.7.1 Assuming greater levels of 'self-remediation'

Transgrid see two potentially material influences on the amount of system strength it needs to procure going forward due to potential 'self-remediation'. Specifically:

- while, as a planning assumption, all BESS within AEMO's IBR forecasts are assumed to be grid-following for the core assessment (as outlined in section 4.1), Transgrid are seeing increasing interest from proponents in deploying batteries in grid-forming mode (which would effectively result in these units 'self-remediating' their general system strength impact); and
- there is currently uncertainty as to who will provide system strength remediation to the New England REZ and stage 2 of the CWO REZ and there is a chance that they may be remediated by a third-party network operator (i.e., as the case for stage 1 of the CWO REZ as outlined in section 2.1.2).

[84] AER, *Valuing emissions reduction*, AER draft guidance, March 2024, p. 4.

Transgrid have therefore undertaken sensitivity tests to investigate how the composition of the optimal portfolio (portfolio option 1) would change, if each of these drivers of self-remediation occur (separately), as well a further sensitivity test that assumes they occur together.

The table below shows how the make-up of portfolio option 1 changes under each of these alternate assumptions.

Table 9.2 – Synchronous condensers and grid-forming BESS under the self-remediation sensitivity tests

Financial year	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Synchronous condensers – cumulative number of units (each providing 1,150MVA$_{\text{fault current}}$)									
Portfolio option 1	–	–	–	8	10	13	14	14	26
BESS self-remediating	–	–	–	7	8	11	11	11	24
REZ self-remediating	–	–	–	7	8	9	9	9	11
Both self-remediating	–	–	–	6	7	8	8	8	10
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
Portfolio option 1	–	50	550	550	550	550	550	550	550
BESS self-remediating	–	50	550	550	550	550	550	550	550
REZ self-remediating	–	50	550	550	550	550	550	550	550
Both self-remediating	–	50	550	550	550	550	550	550	550
Grid-forming BESS – cumulative capacity (MW)									
Portfolio option 1	750	2,600	2,600	3,500	4,800	4,800	4,800	4,800	4,800
BESS self-remediating	750	3,000	3,000	3,650	4,800	4,800	4,800	4,800	4,800
REZ self-remediating	750	2,550	2,550	2,550	3,500	3,500	3,500	3,500	4,800
Both self-remediating	750	2,300	2,300	2,300	2,950	2,950	2,950	3,500	4,100

Compared to portfolio option 1, these sensitivity tests show that:

- an assumption of all BESS self-remediating results in three less synchronous condensers by 2032/33 (and two less over the assessment period) and only a slight change to the timing of new build of grid-forming BESS, or pattern of re-dispatch of synchronous machines;
- self-remediation of the New England REZ and CWO REZ stage 2 results in five less synchronous condensers by 2032/33[85] (and fifteen less over the assessment period) as well as:
    - upgrades to ISP 'modelled' BESS included in the IBR forecasts (which, under this REZ-only sensitivity are *not* assumed to self-remediate) and a specific committed/anticipated BESS upgrade being pushed back to midway through the assessment period (but the same amount of new build of grid-forming BESS over the full assessment period).
    - marginally more gas re-dispatch in the early 2030s due to the cost-efficiency of such re-dispatch relative to the newbuild costs of the synchronous condensers and ISP 'modelled' BESS upgrades.
- BESS self-remediation plus self-remediation of the New England REZ and CWO REZ stage 2 results in six less synchronous condensers by 2032/33 (and sixteen less over the assessment period) as well as:

[85] Importantly, the REZ self-remediation sensitivity results do not imply that system strength remediation is not required for these REZs, but simply that this remediation could be undertaken by a third-party, rather than Transgrid.

- approximately 700 MW less ‘modelled’ BESS included in AEMO’s IBR forecasts (which, under this combined sensitivity *are* assumed to self-remediate) at NNSW and SNSW driven by a reduced efficient level need; and
- marginally more gas re-dispatch in the early 2030s due to the cost-efficiency of such re-dispatch relative to the costs of ISP ‘modelled’ BESS upgrades.

Of the two individual self-remediation sensitivities investigated, the REZ self-remediation sensitivity is found to have the greatest effect on the quantity of system strength remediation required to be procured by Transgrid. While all self-remediation sensitivities find that Transgrid-owned synchronous condensers remain a core part of the portfolio, there is a reduction in the number required.

Transgrid have not investigated how each of the self-remediation sensitivities is expected to affect the overall net market benefits for portfolio option 1, because the purpose of those sensitivities was to test how the resultant portfolio of solutions changes if Transgrid’s obligations itself were to change. Transgrid’s obligations are driven by AEMO’s System Security Reports, which include IBRs contained within the New England REZ and stage 2 of CWO REZ. Transgrid will continue to assess the implications of, and possibility of central remediation of these REZs by a third party network operator.

9.7.2 Grid-forming BESS being able to provide more ‘stable voltage waveform’ support

This sensitivity tests how the optimal portfolio changes if grid-forming BESS can provide more stable voltage waveform support than as currently understood by Transgrid’s power system modelling. This sensitivity is designed to assess how robust the composition of portfolio option 1 is in response to a theoretical improvement in performance of grid-forming BESS for stable voltage waveform support.

To test the impacts of an improved stable voltage waveform support, Transgrid have assumed that a grid-forming BESS could provide 70% more stable voltage waveform support than Transgrid’ preliminary power system studies have estimated (in this case, we assume a 100 MVA grid-forming BESS can stabilise the same amount of IBRs as a 100 MVA synchronous condensers). As a result, grid-forming BESS for this sensitivity are boosted by 5.3 times as opposed to the 3.1 times boost factor applied in portfolio option 1.

Compared to portfolio option 1, the optimal portfolio:

- needs five less synchronous condensers by 2032/33, and four less by 2044/45;
- avoids a significant amount of hydro re-dispatch compared to portfolio option 1 (on account on the grid-forming BESS providing more support under this sensitivity); and
- Delays the need for several hundred megawatts of grid-forming BESS capacity between 2026/27 to 2028/29, but then the same amount of new build grid-forming BESS beyond.

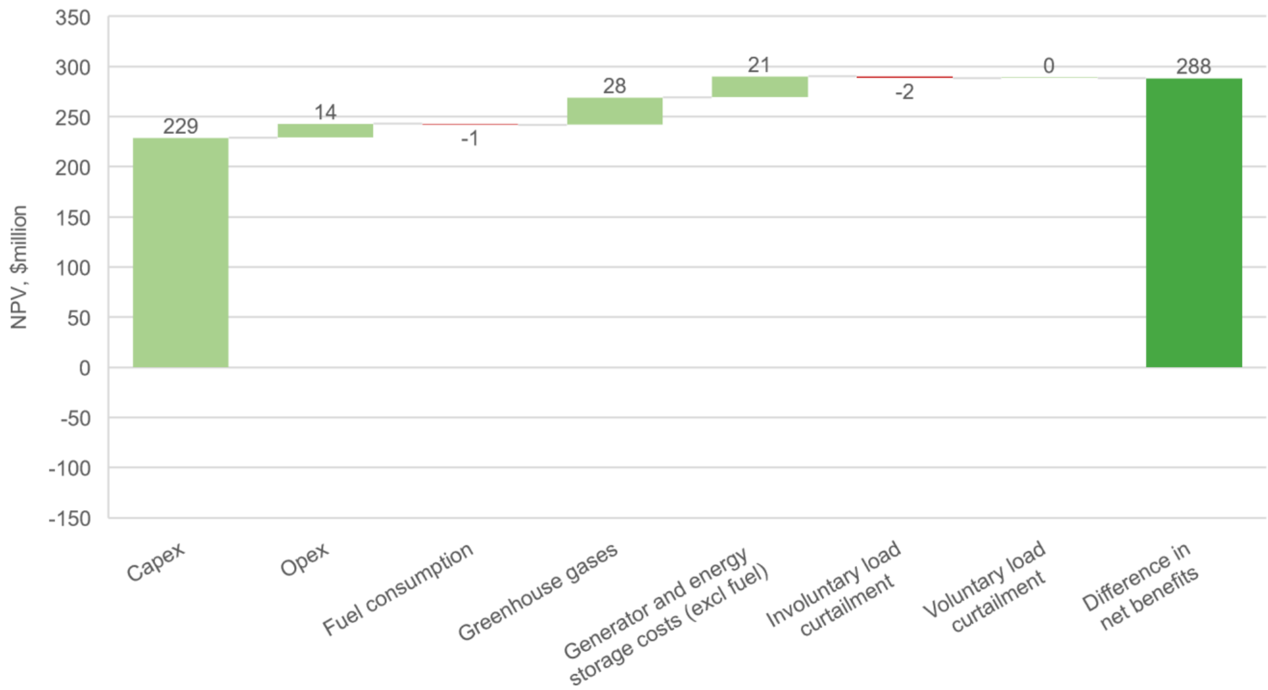
The table below shows how the make-up of portfolio option 1 changes under this alternate assumption.

Table 9.3 – Synchronous condensers and grid-forming BESS assuming grid-forming BESS are able to provide more ‘stable voltage waveform’ support

Financial year	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Synchronous condensers – cumulative number of units (each providing 1,150MVA$_{\text{fault current}}$)									
Portfolio option 1	–	–	–	8	10	13	14	14	26
Increased support	–	–	–	6	7	9	9	9	22
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
Portfolio option 1	–	50	550	550	550	550	550	550	550
Increased support	–	50	550	550	550	550	550	550	550
Grid-forming BESS – cumulative capacity (MW)									
Portfolio option 1	750	2,600	2,600	3,500	4,800	4,800	4,800	4,800	4,800
Increased support	750	1,900	2,300	3,200	4,800	4,800	4,800	4,800	4,800

Under this sensitivity, the expected net market benefits increase by approximately $288 million (in present value terms), compared to under portfolio option 1. This increase in net market benefits is driven primarily by a decrease in capex due to the five less synchronous condensers required, in addition to minor decreases in opex, greenhouse gases and generator and storage costs.

Figure 9.5 – Key changes in the composition of the estimated net market benefits for the increased support sensitivity, compared to portfolio option 1



We intend to undertake more detailed assessments with the PSCAD models of proponent grid-forming BESS that will be supplied as part of the PADR consultation process, to validate or update Transgrid’s current assumptions regarding the performance of grid-forming BESS for stable volage waveform support.

9.7.3 Fully adopting VERs determined by Energy Ministers

As outlined in section 7.1.2, we have used the NSW Government’s recommended VER values in the portfolio formation process for all other portfolio options, i.e., as opposed to those determined by Energy

Ministers and published by the AER in March 2024 (since our portfolio formation was largely complete by March 2024).[86] We have therefore investigated a sensitivity test to see whether the optimal portfolio would differ if we adopted the Energy Minister VER values.

The table below shows how the make-up of portfolio option 1 changes when incorporating Energy Minister VER values.

Table 9.4 – Synchronous condensers and grid-forming BESS with the VER determined by Energy Ministers in the portfolio formation process

Financial year	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Synchronous condensers – cumulative number of units (each providing 1,150MVA$_{\text{fault current}}$)									
Portfolio option 1	–	–	–	8	10	13	14	14	26
Updated VER	–	–	–	8	10	13	14	14	26
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
Portfolio option 1	–	50	550	550	550	550	550	550	550
Updated VER	–	50	550	550	550	550	550	550	550
Grid-forming BESS– cumulative capacity (MW)									
Portfolio option 1	750	2,600	2,600	3,500	4,800	4,800	4,800	4,800	4,800
Updated VER	750	3,000	3,000	3,450	4,800	4,800	4,800	4,800	4,800

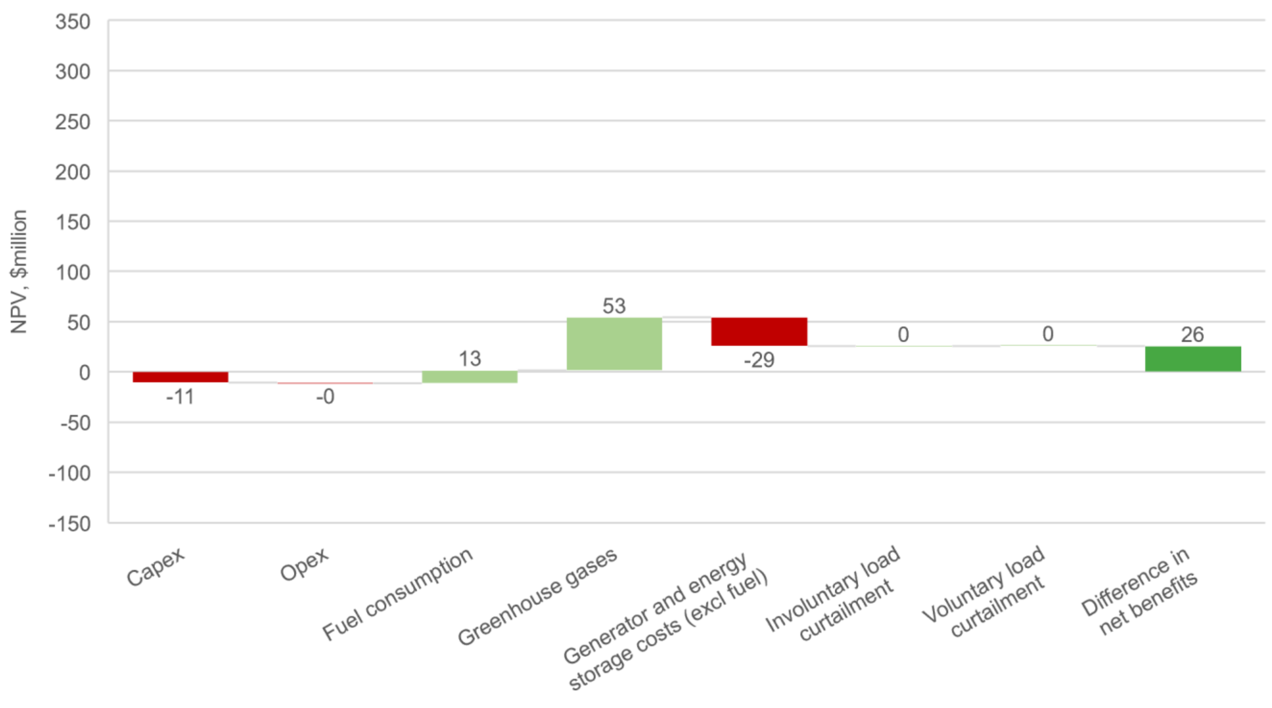
This sensitivity finds that the VER values have an immaterial impact on the optimal portfolio and the only change is that there is a slightly different portfolio of grid-forming batteries between 2026/27 and 2028/29, before aligning in 2029/30.

While Transgrid intends to update the VER used in the PACR assessment to fully reflect those determined by Energy Ministers, it does not expect it will have a material impact on the overall preferred option.

Under this sensitivity, the expected net market benefits increase by approximately $26 million (in present value terms) compared to under portfolio option 1. This modest increase in net market benefits is principally driven by increases in the value attributed to emissions in earlier years, which flows through to benefits from avoiding greenhouse gases and fuel consumption, partially offset by a modest increases in capital expenditure and generator and energy storage costs.

[86] AER, *Valuing emissions reduction*, AER draft guidance, March 2024, p. 4.

Figure 9.6 – Key changes in the composition of the estimated net market benefits for the updated VER sensitivity, compared to portfolio option 1



9.7.4 Assuming a one-year delay to contracting with all grid-forming BESS to a hydro generator upgrade

This sensitivity tests the impact if there was a one-year delay to contracting with all grid-forming BESS (or conversions to become grid-forming), given they represent a relatively novel solution and have a range of timing uncertainties, and a hydro generator that has proposed to upgrade their units to enable them to operate in synchronous condenser mode.

Changing these assumptions in the portfolio optimisation process finds that, compared to portfolio option 1, the optimal portfolio:

- results in one additional synchronous condenser at Wellington in 2028/29 and in total one additional synchronous condenser required over the full assessment period;
- results in effectively the same coal re-dispatch, but with more hydro re-dispatching over the assessment period and a significant increase in gas re-dispatch in 2027/28 (to cover for the delay in build); and
- approximately 700 MW less grid-forming BESS from 2029/30 onwards, with slight differences prior.

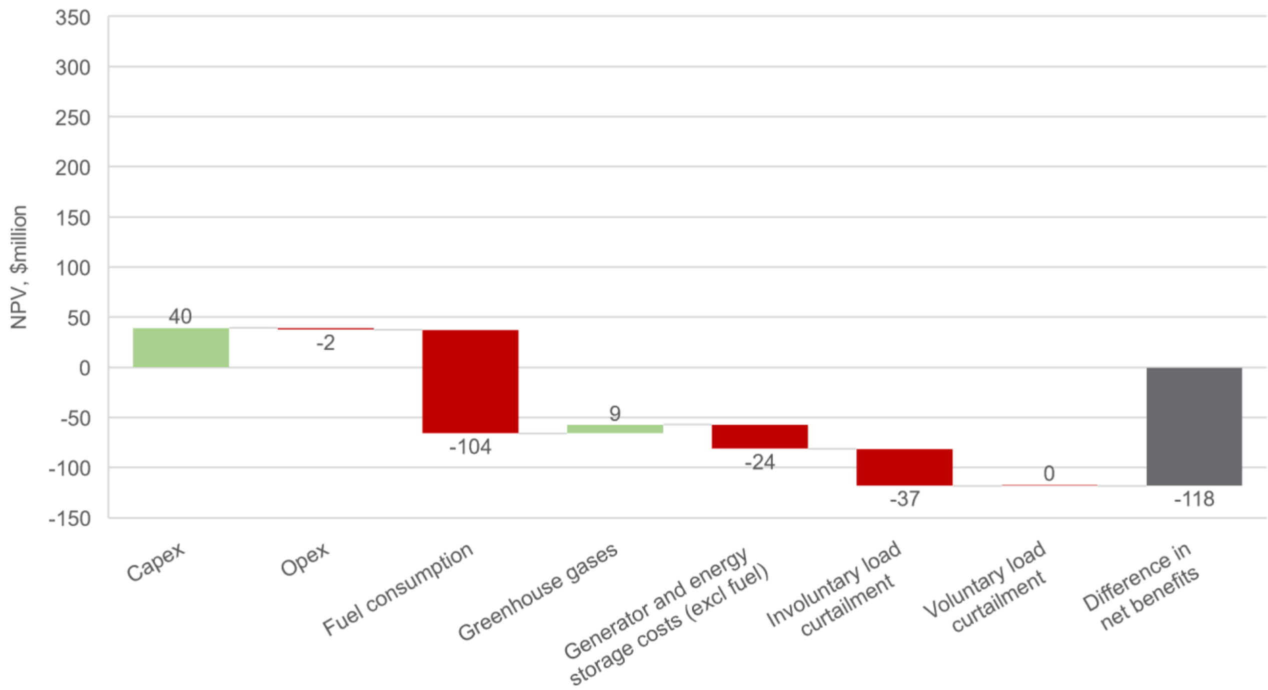
The table below shows how the make-up of portfolio option 1 changes with a one-year delay to contracting with all grid-forming BESS and a hydro generator upgrade.

Table 9.5 – Synchronous condensers and grid-forming BESS assuming a one-year delay to contracting with all grid-forming BESS and a hydro generator upgrade

Financial year	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Synchronous condensers – cumulative number of units (each providing 1,150MVA$_{\text{fault current}}$)									
Portfolio option 1	–	–	–	8	10	13	14	14	26
One-year delay	–	–	–	9	10	14	14	14	27
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
Portfolio option 1	–	50	550	550	550	550	550	550	550
One-year delay	–	50	250	550	550	550	550	550	550
Grid-forming BESS – cumulative capacity (MW)									
Portfolio option 1	750	2,600	2,600	3,500	4,800	4,800	4,800	4,800	4,800
One-year delay	750	2,300	2,550	3,200	4,100	4,100	4,100	4,100	4,100

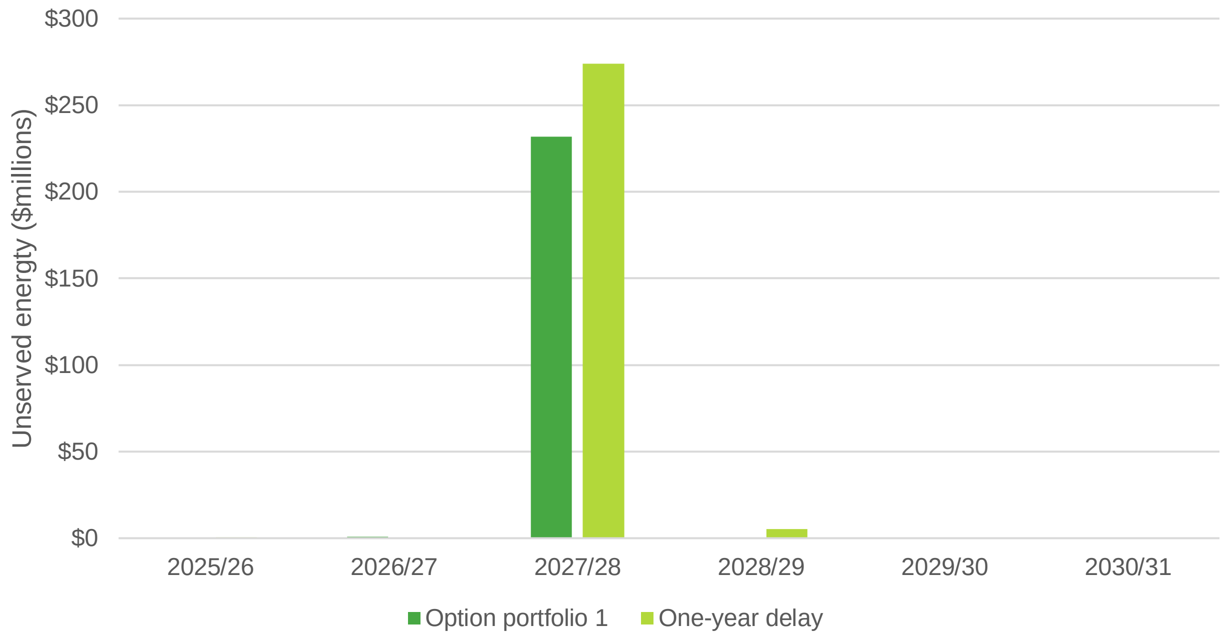
Under this sensitivity, the expected net market benefits decrease by approximately $118 million (in present value terms), compared to under portfolio option 1. This decrease in net market benefits is driven by increases in fuel consumption, involuntary load curtailment and generator and energy storage costs, partially offset by modest decreases in capex and avoided greenhouse gas emissions.

Figure 9.7 – Key changes in the composition of the estimated net market benefits for the one-year delay sensitivity, compared to portfolio option 1



Importantly, assuming a one-year delay to contracting with all grid-forming BESS and a hydro generator upgrade finds that, relative to portfolio option 1, there would be larger and more frequent gaps in system strength in NSW in 2027/28 (and 2028/29 to a lesser extent), which highlights the urgency to progress solutions as soon as possible. The difference in estimated unserved energy included in the analysis for this sensitivity compared to portfolio option 1 is shown in the figure below.

Figure 9.8 – Estimated unserved energy included in the analysis for this sensitivity and portfolio option 1 (undiscounted $2023/24, millions)



9.8 Proposed re-opening triggers

Under the updated Rules relating to a Material Change in Circumstance (MCC), Transgrid is required to set out in the PADR (for consultation and confirmation in the PACR), re-opening triggers for this RIT-T.

Consistent with these new requirements and drawing on the results of the sensitivity assessments outlined above, Transgrid have considered the impact of changes in key underlying assumptions to identify re-opening triggers. Specifically, based on the sensitivity assessment included in this PADR, we consider that the following are expected to form re-opening triggers for this RIT-T:

- credible evidence emerging that we should assume that the majority of new BESS choose to self-remediate their system strength impact in the future by being grid-forming;
- EnergyCo informing us that they will self-remediate system strength impacts of the New England REZ and/or CWO REZ stage 2 by a third-party Network Operator;
- credible evidence emerging that grid-forming BESS are able to provide more 'stable voltage waveform' support than Transgrid currently expects; and
- credible evidence of considerable delays expected (e.g., one-year or more) in contracting with grid-forming BESS (or conversions to become grid-forming) and a hydro generator that has proposed to upgrade their plant to enable it to operate in both generation and synchronous condenser modes.

To be clear, should any of these occur, Transgrid would prepare a letter to the AER confirming that, as a consequence, Transgrid would change the number, or timing, of synchronous condensers as part of the preferred portfolio option. A new RIT-T would not be commenced (which would require significant time to complete and jeopardise Transgrid's ability to provide an adequate amount of system strength at the required time). Instead, Transgrid would refer back to these sensitivities (and any others identified as part of PACR) to confirm that the action Transgrid is proposing to take is considered optimal.

Prior to the publication of the PADR, but after market modelling had concluded, it was announced that the NSW Government and Origin Energy agreed to extend the life of the Eraring Power Station by two years, to 30 June 2027. [87] This delay in Eraring's retirement may also constitute a re-opening trigger.

Transgrid is intending to publish an additional 'RIT-T re-opening trigger consultation document' in the third quarter of 2024 that investigates this (along with other 'what if' sensitivity outcomes). This report will serve as a supplementary report to the PADR and provide an additional consultation opportunity post the PADR but pre-PACR on whether a delay to Eraring's closure (and other possible futures) would constitute a RIT-T re-opening trigger.

In addition, Transgrid considers that certain changes in future AEMO System Strength Reports may also feed into additional potential re-opening triggers at the PACR stage – for example:

- establishment of new system strength nodes; and/or
- removal of existing system strength nodes.

Importantly, based on the sensitivity assessment included in this PADR, Transgrid does not consider the following will constitute re-opening triggers for this RIT-T:

- variations to the published VER;
- synchronous condenser real cost increases compared to those used in the RIT-T analysis;
- real cost increases to the cost to upgrade BESS to be grid-forming; or
- credible changes to the commercial discount rates.

The sensitivity and boundary assessment in this PADR shows that the key findings coming out of this PADR are not sensitive to changes in these variables. However, Transgrid note that these tests have been run on the NPV assessment only in this PADR and expects to further investigate these conclusions using the wider portfolio optimisation process as part of the PACR.

[87] https://www.energy.nsw.gov.au/sites/default/files/2024-05/NSW-202405-Public-summary-of-Generator-Engagement-Project-Agreement.pdf

10 PADR conclusion

While portfolio option 1 is currently the most credible and preferred portfolio option at this stage of the RIT-T, net market benefits would increase if portfolio option 2 (accelerated synchronous condensers) or portfolio option 3 (confidential proposal) were proven to be feasible. As such, there is significant merit in continuing to investigate whether the key uncertainty involved with each can be resolved over the course of this RIT-T, individually or in combination.

Specifically, between now and the PACR, Transgrid will:

- investigate the advancement the procurement and commissioning of no-regret synchronous condensers. This would require commencement of procurement of synchronous condensers prior to the conclusion of the RIT-T and AER's approval of a contingent project application (CPA);
- confirm the technical feasibility of the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West. We work with the proponent of this solution following this PADR to determine this;
- identify credible approaches to minimise expected network support payments without materially impacting the optimal portfolio of solutions (e.g., contracting with less gas, coal or hydro units); and
- identify additional non-network solutions that can contribute to meeting system strength gaps at Armidale, Sydney West, Newcastle, Wellington and Darlington Point in 2027/28. These additional non-network solutions must be capable of providing protection-quality levels of fault current, such as new synchronous condensers, new synchronous generators or modifications to existing units; and
- assess the technical feasibility of each proposed grid-forming battery project via a request for PSCAD models (which is considered necessary before each project can be considered part of the optimal portfolio of solutions at the final PACR stage).

The outcomes of these will be included in the ultimately preferred option of this RIT-T.

Consistent with the new MCC provisions in the NER and drawing on the results of the sensitivity assessments undertaken in this PADR, our PADR considers the impact of changes in key underlying assumptions to identify re-opening triggers. We are very interested in stakeholder views on these triggers and the associated analysis undertaken (and proposed for the PACR).

As input into the PACR market modelling, Transgrid will assess the technical and commercial credibility of all non-network options selected as part of the PADR's preferred portfolio of solutions (which were assumed to be technically and commercially credible). Where non-network solutions are determined to not be credible, these options will not progress through the RIT-T and procurement process. Alternative solutions (either non-network or network) would be required to fill its place in the optimal portfolio of solutions.

Submissions and next steps

Transgrid welcomes written submissions on materials contained in this PADR, including on the proposed re-opening triggers.

Submissions are due on 2 August 2024.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[88] In the subject field, please reference 'Meeting system strength requirements in NSW RIT-T PADR'.

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

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

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PADR with the requirements of the National Electricity Rules version 211.

Table A.1 – Compliance checklist of PADR with NER version 211

Rules clause	Summary of requirements	Relevant section(s) in the PADR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	5
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	0 & Appendix E
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	5 & 0
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & 8
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	7.3
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	0
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	0
	(8) the identification of the proposed preferred option;	10
	(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.	10

Appendix B How the changes in key assumptions since the PSCR have been translated into updated expected system strength requirements

The three subsections below set out the expected minimum and efficient level of system strength (i.e., the requirements under Clause S5.1.14), as well as the Shortfall requirements.

The minimum requirements remain the same as set out in the PSCR. The efficient level of system strength and Shortfall have changed, in light of the above changes in key assumptions.

B.1 Minimum level of system strength (from 2 December 2025)

From 2 December 2025, we are required as NSW's SSSP to meet NSW's entire minimum fault level requirements in full, at each of the NSW nodes identified by AEMO (rather than just filling a declared Shortfall).

AEMO has specified the pre- and post-contingency minimum requirements at six NSW nodes, as described in the table below. These values have not changed since the PSCR, nor between the 2022 and 2023 AEMO System Strength Reports, since they are minimum requirements that are not dependent on specific REZ or providers of system strength (and they are unlikely to change in the coming few years).

Table A.2 – New South Wales minimum fault level requirements

Node	System strength need (fault level, MVA)		Need date	Estimated need duration
	Pre-contingency	Post-contingency		
Armidale 330 kV	3,300	2,800	From 2 December 2025 onwards	100% of time
Buronga 220 kV	1,755	To be determined		
Darlington Point 330 kV	1,500	600		
Newcastle 330 kV	8,150	7,100		
Sydney West 330 kV	8,450	8,050		
Wellington 330 kV	2,900	1,800		

Source: AEMO, *2023 System Strength Report*, December 2023, p. 16.

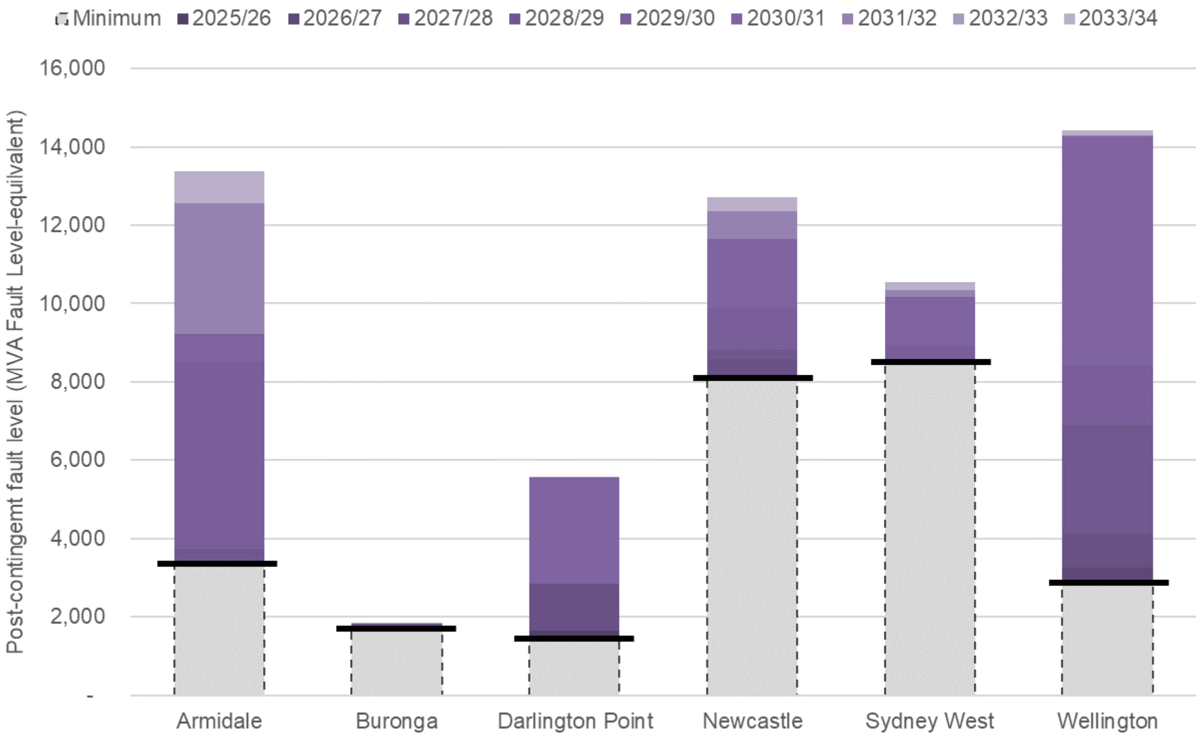
The need is therefore to meet minimum fault level requirements in full at each node at all times of the year, from 2 December 2025 onwards. For example, at the Newcastle node, network and/or non-network solutions must be in place to meet a pre-contingency fault level of 8,150 MVA and a post-contingency fault level of 7,100 MVA fault level for all periods of the year. These solutions may include existing synchronous generators dispatched in the energy market.

B.2 Efficient level of system strength (from 2 December 2025)

The new system strength framework also requires us to provide sufficient system strength services to ensure the efficient amount of new inverter-based resources (i.e., inverter-based renewable generation and inverter-based storage systems) will remain stable in steady stage conditions and remain synchronised following credible contingency events.[89]

Since the PSCR, we have updated the estimated approximate fault level that would be required to ensure a stable voltage waveform for new connecting renewables, as an indicative proxy for the quantum of system strength services required to meet the efficient level, above and beyond the minimum fault level requirements in light the key developments outlined above. This is shown in the figure below for the core PADR modelling.[90]

Figure A.1 – NSW's combined minimum pre-contingency fault level requirements from 2 December 2025 and efficient fault level projections to 2032/33, as a proxy for stable voltage waveform



Note: 1) As in the PSCR, the analysis is on a pre-contingency basis, using the Available Fault Level methodology, assuming Short Circuit Ratio (SCR) requirements of 3 for renewables (except CWO REZ stage 1) less an alpha factor of 1.2. Stage 1 of the CWO REZ (5.84 GW) is included within this analysis, as is the proposed remediation (7 x 250MVA rated synchronous condensers in system normal). Note that ensuring that minimum fault levels are achieved in NSW also provides system strength services to stabilise new connecting renewables. Also note that Buronga's minimum post-contingency fault level requirements have not been established – for this chart an estimate has been used.

B.3 System strength Shortfall (1 July 2025 – 1 December 2025)

On 15 December 2022, AEMO gave notice to Transgrid under clause 11.143.14 of the National Electricity Rules (NER) that a system strength Shortfall is projected to occur at the Newcastle (1,190 MVA) and Sydney West (1,026 MVA) system strength nodes from 1 July 2025. This reflected AEMO's analysis and

[89] AEMC, 21 October 2021, Efficient management of system strength on the power system, rule determination, https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

[90] This figure shows the efficient levels for the core modelling undertaken in this PADR and does not cover the three self-remediation sensitivities (which have different efficient levels on account of what each are testing).

expectations at the time of that notice about the delivery timing of the Central West Orana (CWO) REZ and is an update to previously declared Shortfalls (including within the 2022 System Strength Report).

On 1 December 2023, AEMO published revised (increased) shortfalls of 1,420 MVA and 1,165 MVA at Newcastle and Sydney West, respectively, as part of the 2023 System Strength Report, as set out below.[91] On 20 December 2023, AEMO gave a revised notice to Transgrid under clause 11.143.14 of the NER covering these increased shortfalls.

Table A.3 – Summary of system strength shortfall requirements

Node	System strength need	Need date	Estimated need duration
Newcastle 330 kV	1,420 MVA of additional fault current	1 July 2025 to 1 December 2025	3% of the time
Sydney West 330 kV	1,165 MVA of additional fault current	1 July 2025 to 1 December 2025	10% of the time

Source: AEMO, *2023 System Strength Report*, December 2023, p. 16.

Based on AEMO's assessment of the Shortfall, the system strength services are likely to be required for approximately 10% of the time to support fault levels at Sydney West and approximately 3% of the time at Newcastle. However, depending on the constraints and capabilities of different technologies to start-up and respond instantaneously, non-network solutions providing system strength services may be required to operate for longer periods of time to meet those needs.

We note that this Shortfall was in part driven by the planned retirement of Eraring Power Station in August 2025. Due to the delayed retirement of Eraring Power Station, we expect AEMO to update and reissue a Shortfall notification.

[91] AEMO, *2023 System Strength Report*, December 2023, p. 3.

Appendix C Summary of the key ‘post-processing’ processes Transgrid has applied to the PLEXOS output

We have undertaken three key ‘post-processing’ processes to the PLEXOS output, as outlined in the sections below.

C.1 System strength solution coefficient PSS®E feedback loop

System strength is a dynamic characteristic within a power system, exhibiting non-linear behaviour. The fault current output of an individual unit is contingent upon the operational status of other units and the condition of the transmission infrastructure at any given moment. For the PLEXOS system strength modelling, we needed to ensure that we are not overstating or underestimating the fault level coefficients by each of the units.

The initial system strength coefficient for each solution was calculated based on a portfolio of synchronous machines being online and providing high levels of fault current in the network. However, due to the dynamic nature of system strength, when the system strength coefficients in PLEXOS were validated with PSS®E, deviations were observed. These coefficients were tuned in a feedback loop where the market model would identify the system strength portfolio required to meet the need, and these solutions were fed into the power system model (PSS®E) to calculate more accurate system strength coefficients. These tuned coefficients were then used in the final modelling results with a much higher level of accuracy than the original coefficients.

C.2 Identification of gaps in the network analysis

Since the PLEXOS market model is a simplified representation of the transmission network where all IBRs are located at the node, it builds solutions that provide system strength at the node, not close to the actually expected connection point of the IBRs, where they would be more effective. To ensure the solutions chosen by PLEXOS can effectively meet the system strength need at the expected point of connection of the IBRs, the portfolio of solutions chosen by PLEXOS was subsequently modelled in PSS®E, where it identified system strength gaps at Parkes and Broken Hill that wasn’t identified in PLEXOS.

Transgrid’s analysis of this gap resulted in a grid-forming BESS at or near to Parkes being modelled as a committed or anticipated BESS, as opposed to a proposed BESS, so it would be selected as a system strength solution. Transgrid have also manually assessed the solution to the Broken Hill need outside of the market modelling process due to its large electrical distance from the nearest system strength node (as outlined in section 4.4).

C.3 ‘Integerisation’, location of new build synchronous condenser and BESS solutions and gap assessment

As part of the system strength solution portfolio output, the PLEXOS market model provides synchronous condenser and BESS build paths that meet system strength requirements. However, due to tractability challenges, this output exists as a linear optimisation (i.e. it builds fractions of a solution that can in reality only be built in discrete chunks), necessitating manual conversion to an integer build path (i.e. rounding up or down to whole numbers).

Importantly, while the values may be rounded, the fundamental structure and composition of the synchronous condensers in the linear and integer build paths remain consistent, preserving the overall integrity of the synchronous condenser build path relative to the original PLEXOS output.

To ensure the PLEXOS informed synchronous condenser build path effectively meets our system strength requirements, the integer build path then undergoes validation in PSS®E to ascertain its efficacy under real-world network conditions. This validation process entails simulating various scenarios, including critical planned outages, maintenance requirements, and N-1 contingencies, to assess the system's ability to meet strength requirements. Synchronous condensers (but not BESS) were either relocated or their commissioning dates adjusted based on the insights provided by the PSS®E analysis. The integer build path is then fed into PLEXOS' Short-Term model.

Appendix D NPV sensitivity results

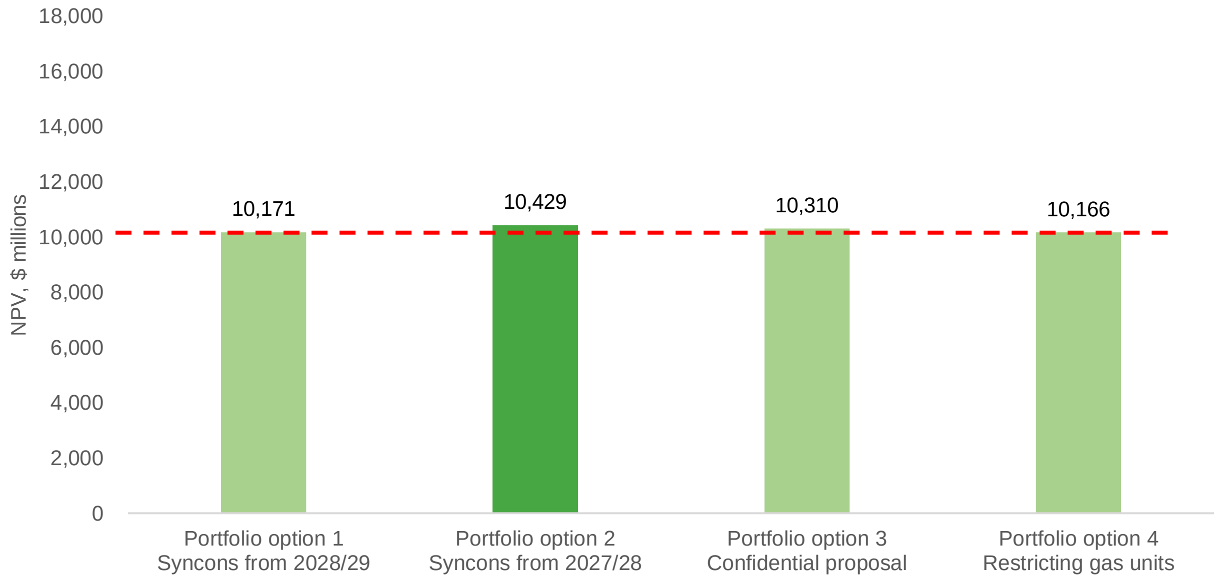
This appendix sets out the range of sensitivities we tested the impact on the portfolio rankings of, i.e.:

- 25% higher and lower VER values, (i.e., consistent with the MCE guidance);[92]
- 30% higher and lower VCR values (i.e., consistent with the AER's state level of confidence);[93]
- 25% higher and lower assumed synchronous condenser costs (both capital and operating costs);
- 25% higher and lower grid-forming BESS upgrade costs; and
- lower and higher commercial discount rates (as discussed in section 7.4).

D.1 Higher and lower assumed value of emissions reduction

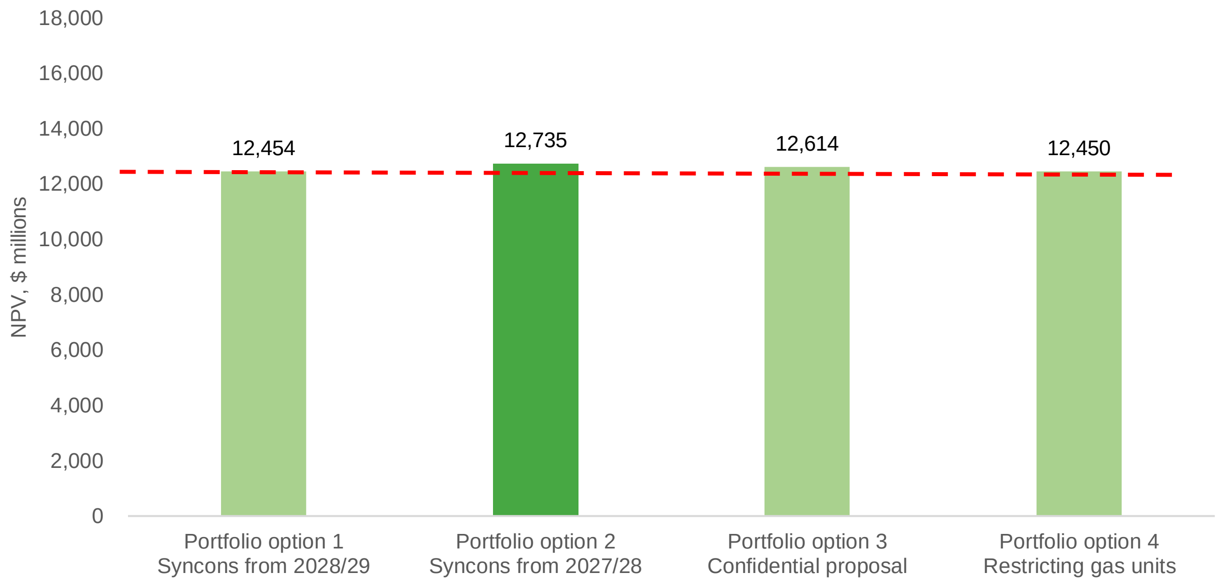
We present the net market benefit results of assuming 25% higher and lower assumed value of emissions reduction (VER) in the figures below. The figures for VER sensitivities show that the options are effectively the same and differences are within 5% of option 1. Net benefits do not decrease below $10 billion for any portfolio options in the low VER sensitivity.

Figure A.2 – NPV results for each of the portfolio options with 75% VER - $millions



92 https://www.aemc.gov.au/sites/default/files/2024-04/MCE%20statement%20on%20interim%20VER.pdf
93 AER, *Widespread and long duration outages – values of customer reliability*, Final conclusions, September 2020, p. 8.

Figure A.3 – NPV results for each of the portfolio options with 125% VER - $millions



On boundary testing, we find that there are no positive VER values that could result in portfolio option 1 exhibiting zero or negative net benefits, and no realistic VER values that could result in a change in the ranking of other portfolio options relative to portfolio option 1. As such, we conclude that there is no feasible change in the VER that would change the results of our core NPV assessment.

We present the results of boundary testing in the table below.

Table A.4 – Value of emissions reduction boundary tests

Key findings of this PADR	VER
Portfolio option 1 having significant net benefits[94]	N/A
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	N/A
The confidential proposal to provide synchronous condenser services increasing the expected net benefits	N/A
Restricting the number of gas units decreases the estimated net benefits	240%

D.2 Higher and lower assumed value of customer reliability

We present the net market benefit results of assuming 30% higher and lower assumed value of customer reliability (VCR) in the figures below. The figures for VCR sensitivities show that the options are effectively the same and differences are within 5% of option 1. Net benefits do not fall below $10 billion for any portfolio options.

94 We note that this boundary test, for all sensitivities, is based on the capped USE values and, if this USE was included, the boundaries, where they exist, would be even more unrealistic.

Figure A.4 – NPV results for each of the portfolio options with 70% VCR - $millions

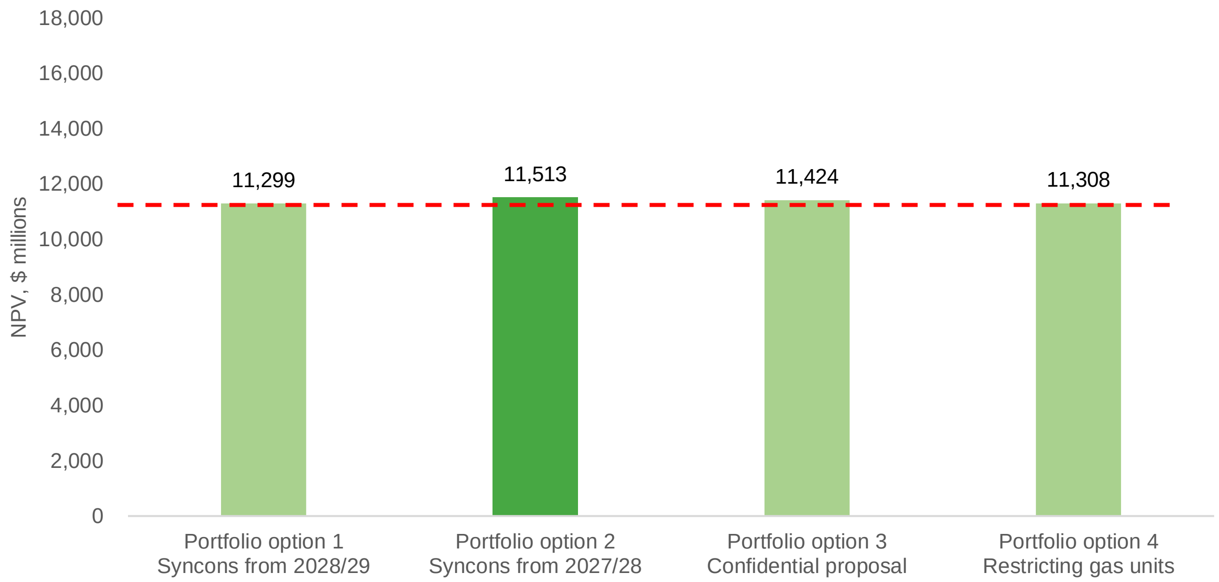
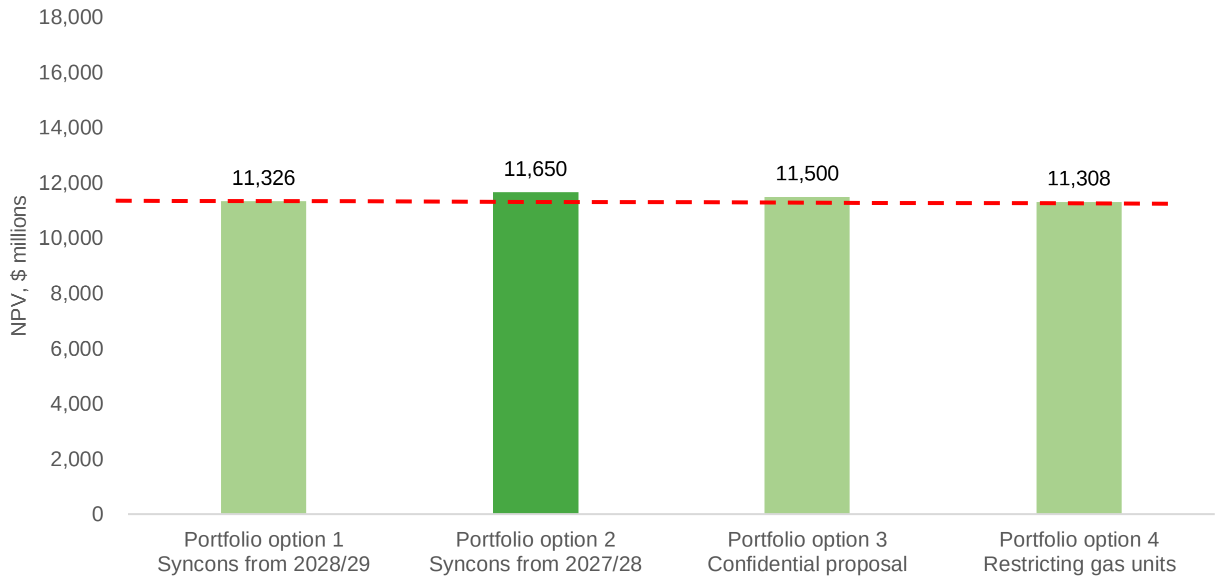


Figure A.5 – NPV results for each of the portfolio options with 130% VCR - $millions



On boundary testing, we find that there are no positive VCR values that could result in portfolio option 1 exhibiting zero or negative net benefits, and no realistic VCR values that could result in a change in the ranking of other portfolio options relative to portfolio option 1 – with the exception of if we assume VCR values are at least 10% lower than the AER values.

If we assume VCR values that are approximately 10% lower than the AER values, portfolio option 4 is ranked equally with portfolio option 1, i.e., they have the same estimated net market benefits. At this stage, this is not considered a material boundary value and we note that, if VCR values are assumed to be 30% lower than the AER values (i.e., consistent with the lower confidence level quoted by the AER), portfolio option 4 is only preferred over portfolio option 1 by approximately $9 million (in present value terms). On balance, and considering the other sensitivities and boundary values, we consider the finding that, if we restrict the number of gas units assumed to be contracted with, the expected net market benefits decrease (i.e., portfolio option 4 is ranked below portfolio option 1) to be robust.

We present the results of boundary testing in the table below.

Table A.5 – Value of customer reliability boundary tests

Key findings of this PADR	VCR
Portfolio option 1 having significant net benefits	N/A
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	N/A
The confidential proposal to provide synchronous condenser services increasing the expected net benefits	N/A
Restricting the number of gas units decreases the estimated net benefits	-10%

D.3 Higher and lower assumed synchronous condenser costs

We present the results of assuming 25% higher and lower assumed synchronous condenser costs in the figures below. The figures for synchronous condenser cost sensitivities show that the options are effectively the same and differences are within 5% of option 1. Net benefits do not decrease below $10 billion under any portfolio options.

Figure A.6 – NPV results for each of the portfolio options with 125% synchronous condenser costs - $millions

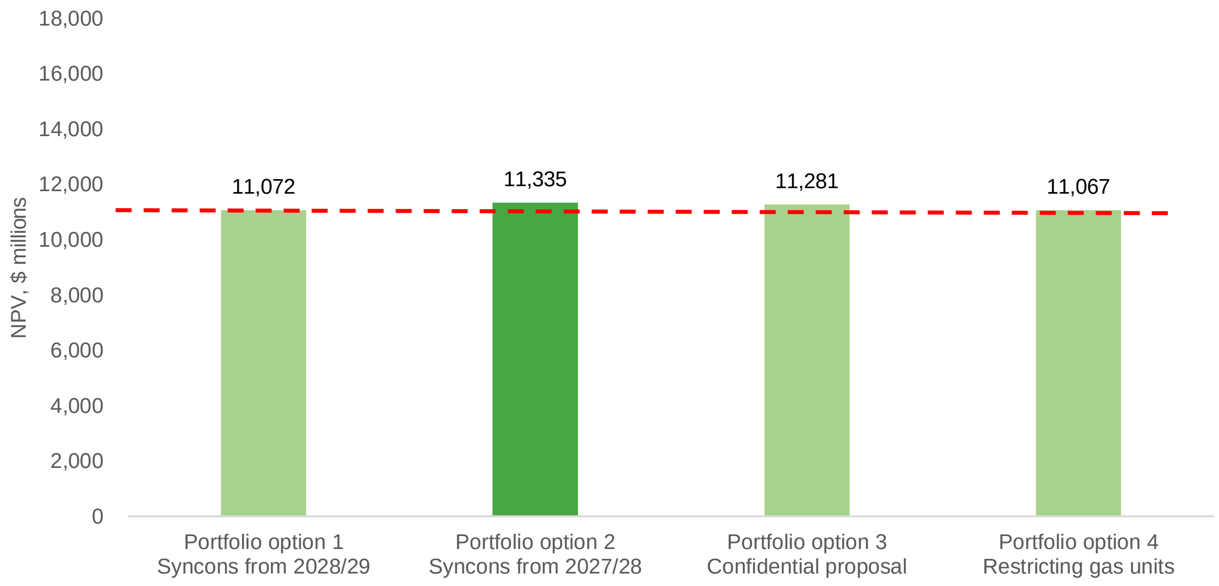
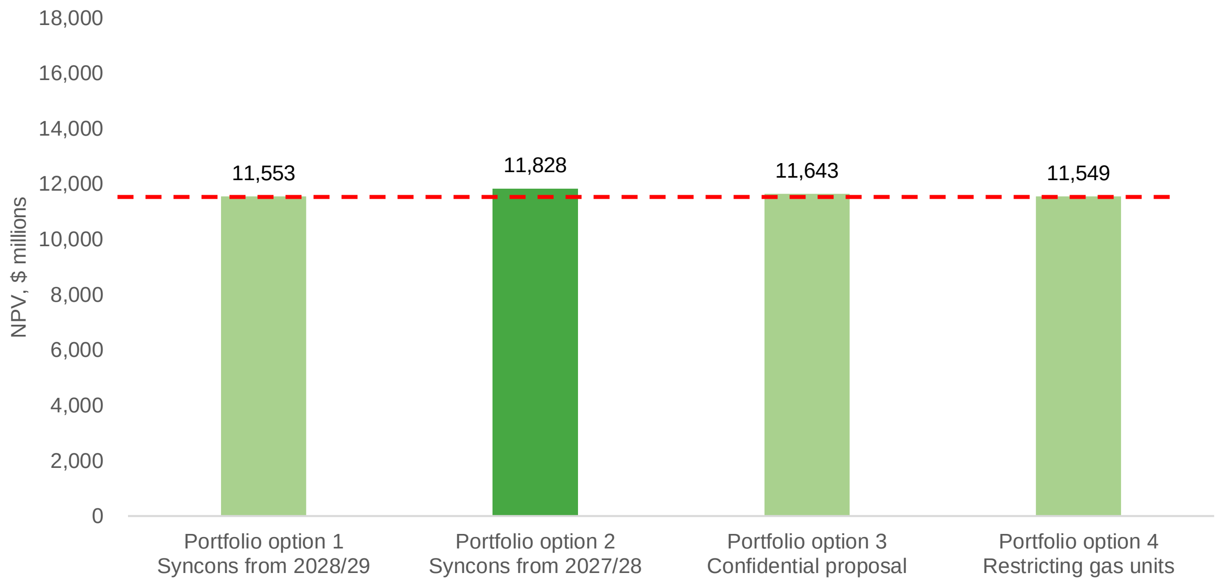


Figure A.7 – NPV results for each of the portfolio options with 75% synchronous condenser costs - $millions



On boundary testing, we find that there would need to be a more than 1,000% increase in synchronous condenser costs for any options not to have net benefits. In addition, there would need to be a 62% decrease in synchronous condenser costs for the ranking of any portfolio options to change relative to portfolio option 1. As such, we conclude that there is no feasible change in synchronous condenser costs that would change the results of our core NPV assessment.

We present the results of boundary testing in the table below.

Table A.6 – Synchronous condenser cost boundary tests

Key findings of this PADR	Synchronous condenser costs
Portfolio option 1 having significant net benefits	1,176%
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	1,116%
The confidential proposal to provide system strength services increasing the expected net benefits	-62%
Restricting the number of gas units decreases the estimated net benefits	N/A

D.4 Higher and lower assumed BESS upgrade costs

We present the results of assuming 25% higher and lower assumed BESS upgrade costs in the figures below. The figures for BESS upgrade cost sensitivities show that the options are effectively the same and differences are within 5% of option 1. Net benefits do not decrease below $10 billion under any portfolio options.

Figure A.8 – NPV results for each of the portfolio options with 125% BESS upgrade costs - $millions

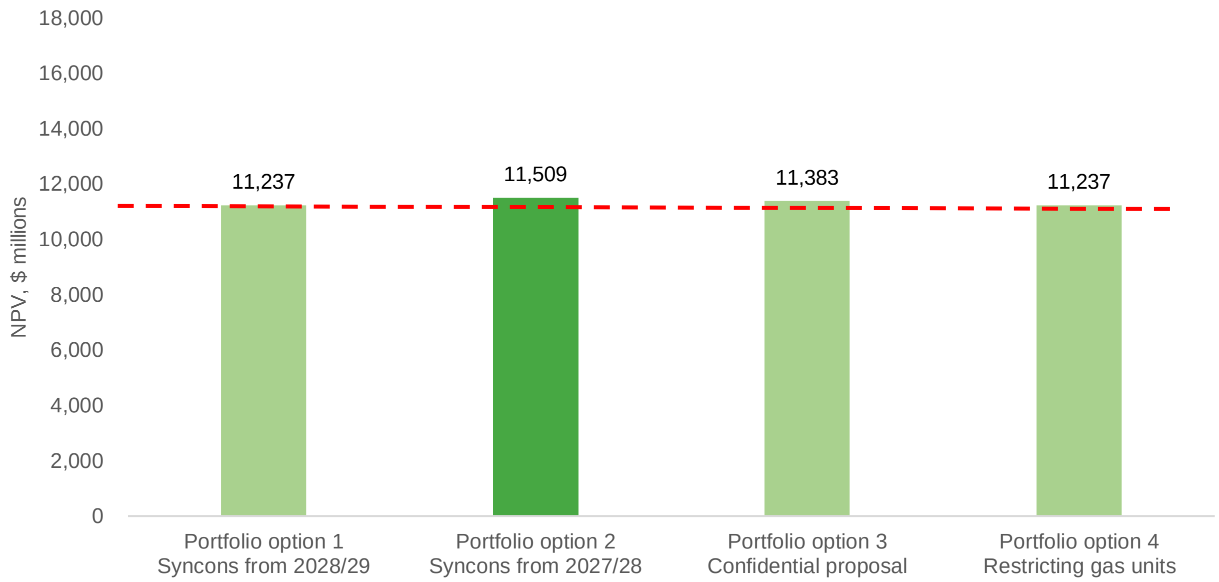
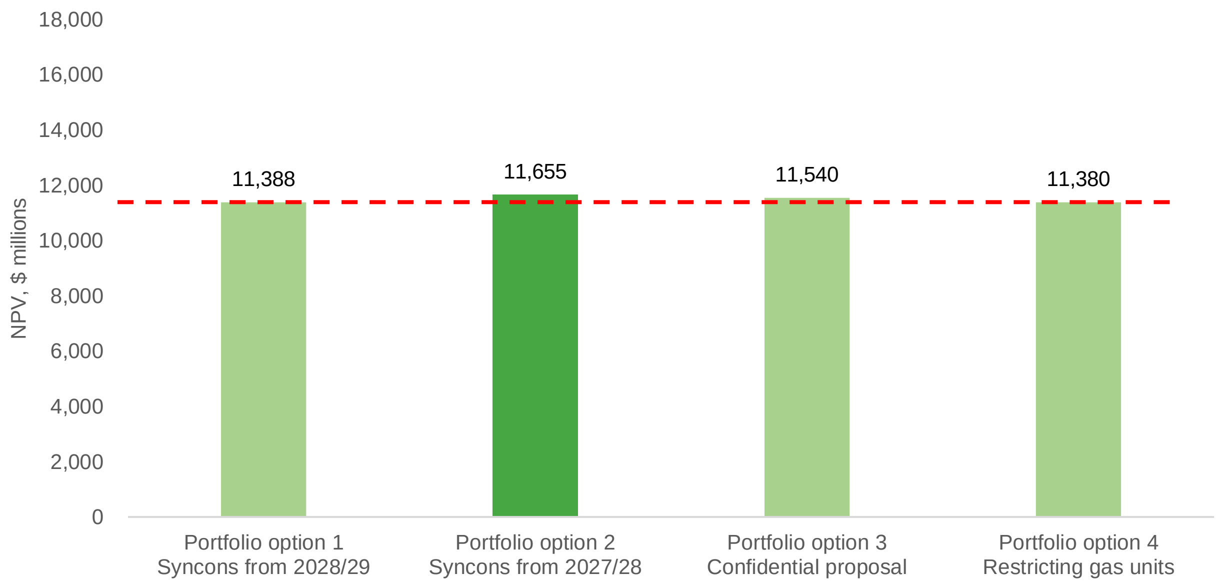


Figure A.9 – NPV results for each of the portfolio options with 75% BESS upgrade costs - $millions



On boundary testing, we find that there would need to be a more than 3,763% increase in BESS upgrade costs for any options not to have net benefits. In addition, there would need to be a 31% increase in BESS upgrade costs for the ranking of any portfolio options to change relative to portfolio option 1 – however, we note that at 31% higher assumed BESS upgrade costs, portfolio option 4 and portfolio option 1 would have equal estimated net benefits and these upgrade costs would have to be significantly greater for there to actually be a material difference in the estimated net benefit of these two portfolio options. As such, we conclude that there is no feasible change in BESS upgrade costs that would change the results of our core NPV assessment.

We present the results of boundary testing in the table below.

Table A.7 – BESS upgrade cost boundary tests

Key findings of this PADR	BESS upgrade costs
Portfolio option 1 having significant net benefits	3,763%
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	N/A
The confidential proposal to provide system strength services increasing the expected net benefits	1,070%
Restricting the number of gas units decreases the estimated net benefits	31%

D.5 Higher and lower assumed discount rate

We present the results of assuming higher and lower discount rates in the figures below. Discount rate sensitivity results set out in the figures below demonstrate:

- a discount rate of 3.61% increases net market benefits for each option to over $17 billion. All options are effectively the same given differences are within 5% of option 1; and
- a discount rate of 10.50% decreases net market benefits for each option to between $7.6 and $7.9 billion. All options are effectively the same given differences are within 5% of option 1.

Figure A.10 – NPV results for each of the portfolio options with 3.61% discount rate - $millions

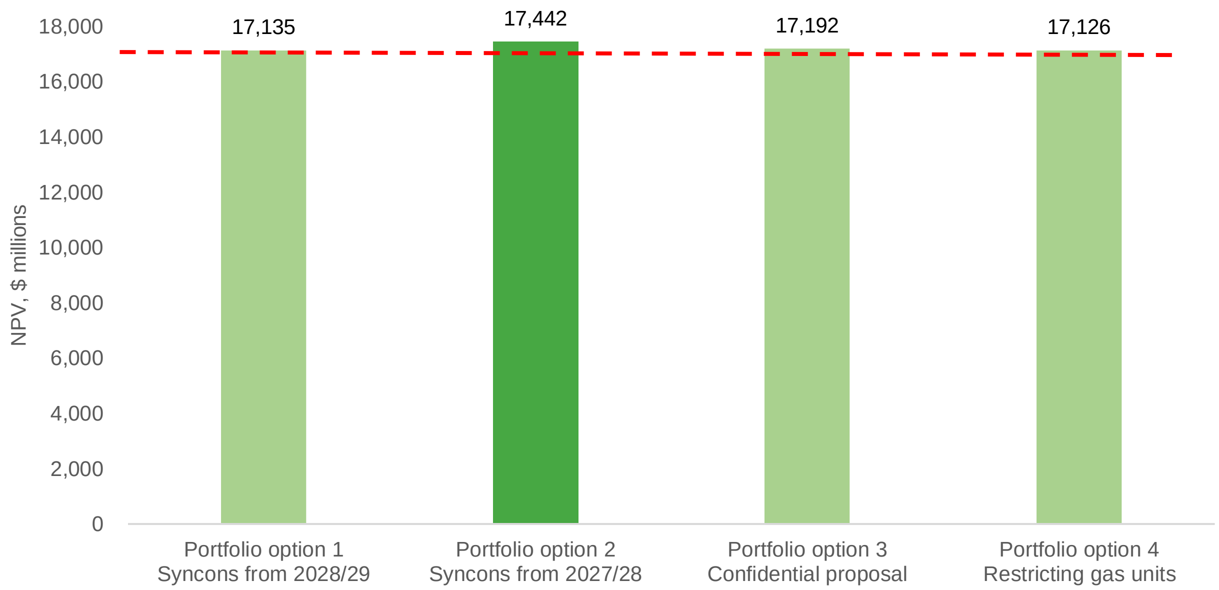
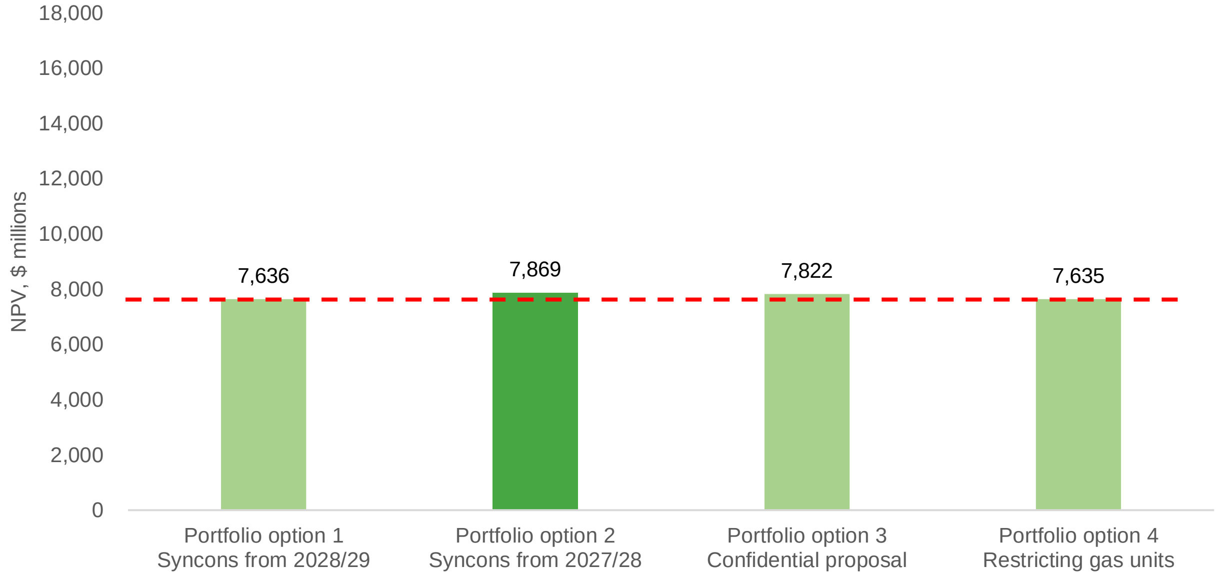


Figure A.11 – NPV results for each of the portfolio options with 10.5% discount rate - $millions



On boundary testing, we find that there would need to be a discount rate of 83% for portfolio option 1 not to exhibit any net benefits. In addition, we find that there would need to be a discount rate of less than 2.4% or greater than 12.1% for the ranking of any portfolio options to change relative to portfolio option 1. As such, we conclude that there is no feasible discount rate that would change the results of our core NPV assessment.

We present the results of boundary testing in the table below.

Table A.8 – Discount rate boundary tests

Key findings of this PADR	Discount rate
Portfolio option 1 having significant net benefits	82.71%
Accelerating the delivery of synchronous condensers by a year increases the expected net benefits	97.31%
The confidential proposal to provide system strength services increasing the expected net benefits	2.37%
Restricting the number of gas units decreases the estimated net benefits	12.17%

Appendix E Additional detail on all non-confidential points raised as part of consultation on the PSCR

In addition to the responses to the EOI, we received submissions from five parties directly in response to the PSCR, four of which have been published on our website (one requested confidentiality).[95] The four parties who did not request confidentiality are:

- EnergyAustralia;
- Origin Energy;
- Smart Wires; and
- Tesla.

There were ten broad areas that were raised across these submissions:

- further specification of the identified need;
- the scope of the network components;
- option value and the timing of options;
- AEMO directions and involuntary load shedding under the base case;
- treatment of non-network option costs;
- how inter-regional assets are assessed;
- transparency regarding the modelling;
- how the broader ongoing work program on system services will affect this RIT-T (and vice versa);
- location of new system strength resources; and
- the use of modular power flow control (MPFC) technology.

The key matters raised in non-confidential submissions are summarised and responded to in the following subsections.

E.1 Further specification of the identified need

EnergyAustralia requested additional detail regarding the 'efficient' system strength level, which depends on changes in the technology mix over time. Specifically, EnergyAustralia made a number of requests regarding information contained in the PADR as summarised, and responded to, in the table below.[96]

[95] https://www.transgrid.com.au/projects-innovation/meeting-system-strength-requirements-in-nsw
[96] EnergyAustralia, pp. 2-3.

Table A.9 – EnergyAustralia requests regarding further specification of the identified need

EnergyAustralia requested that the PADR:	Transgrid response
Articulates how future editions of IBR forecasts in AEMO's annual system strength reports will form part of Transgrid's obligation to meet the "system strength standard specification" and "forecast system strength requirements" under S5.1.14.	The IBR forecasts are prepared by AEMO for the 10 years from 1 December 2022 and are reviewed annually. Transgrid's obligation is to meet the standard under Clause S5.1.14 from 2 December 2025.[97] The obligation is a 'rolling' three-year requirement and so any changes in subsequent AEMO System Strength Reports will be assessed in terms of their materiality on the conclusions of this RIT-T. As outlined in Section 2.1, we have used the latest (2023) AEMO System Strength Report for the analysis in this PADR. In addition, as outlined in section 1, despite the three-year binding period, we consider it will be most efficient to consider solutions that can continue to provide system strength beyond this three-year period due to the complexity and timeframe involved in both the RIT-T and procurement processes, as well as the inherent long-term ability of the solutions proposed to provide system strength. We have therefore assessed all solutions over a twenty-year assessment period and note that components of the options later in this period are currently considered on an indicative basis only (and which would be subject to a later RIT-T and procurement process).
Explains whether and how forecast system strength requirements beyond AEMO's 10-year horizon are articulated, given the RIT-T analysis will extend 20 years, to 2041-42.	Section 2.1 outlines how the IBR forecasts have been determined for all years of the PADR assessment, including beyond AEMO's 10-year forecasts. Baringa's market modelling report covers how these have been translated into specific system strength requirements.
Explains what effects (if any) will arise through the declaration of new system strength nodes in AEMO's reporting framework over the assessment period.	If any new system strength nodes are declared in the future, we would assess the expected impact on the preferred option coming out of this RIT-T and whether the declaration constitutes a material change in circumstances for this RIT-T. As part of this we would consider the appropriate action to take, including whether a new RIT-T focussed on how best to procure the required system strength for the new node(s) is appropriate.
Explains how the duration of system strength needs, as expected to be determined via the OSM, affect the scope of system strength 'capacity' that it will plan towards and eventually procure.	The duration of system strength needs does not affect the scope of system strength capacity we are planning to procure since the need is to meet the requirements 100% of the time (using reasonable endeavours). As outlined at the end of section 2, in May 2023, the AEMC announced that it would no longer pursue the OSM approach to schedule and dispatch network services (including system strength). We note that the OSM was expected to affect contracting decisions, which sit outside of the scope of the RIT-T. The OSM outcomes were therefore expected to be informative but will not drive a change in the duration of the identified need.
Provides technical analysis on how it has translated AEMO's four criteria relating to voltage waveforms into a single minimum MVA fault level metric.	Transgrid's PADR market modelling uses fault current as the proxy for stable voltage waveform support, via the Available Fault Level (AFL) calculation methodology as

[97] Specifically, Transgrid's obligation to meet the standard under Schedule 5.1.14 from 2 December 2025 is framed around the 'system strength standard specification' (which defines the binding requirement as the forecast requirements determined three years prior).

	specified by AEMO in its System Strength Impact Assessment Guidelines (v2.1, 2023). To account for the 'handicap' that grid-forming batteries face when its stable voltage waveform support is 'valued' using its fault current, Transgrid has introduced a 'boost factor' concept into its market modelling (and has also investigated a sensitivity that varies this – see section 9.7.2). We plan to use a mixed stead-state and EMT modelling approach for the PACR.
Advises to what extent minimum post contingency fault levels from 2 December 2025 and efficient fault level projections to 2033 are suitable as a proxy for stable voltage waveform.	AEMO has advised in the System Strength Requirements Methodology (section 5.2.2) that available fault level (AFL) calculations are suitable for assessing the future network where outside the appropriate timeframe for EMT studies. AEMO suggests that EMT studies are preferred only within a 1 to 2 year time horizon due to model accuracy requirements. As this RIT-T covers a longer time span, Transgrid has used the suggested available fault level calculation to infer the stability of the voltage waveform.
Considers other flexibility that AEMO has provided the SSSP in its IBR forecasts, including the potential to adjust near term forecasts as more information emerges on IBR and market network service facilities, and how to treat distribution-connected IBR.	Section 2.1 outlines how the IBR forecasts have been determined for all years of the PADR assessment, including the approaches taken to reflect the latest information (as well as why we consider them appropriate).
Clarifies whether Transgrid intends to conduct further detailed analysis and present a more accurate (i.e. reduced) estimate of the investment need in light of the efficient MVA values reflecting an upper limit due to the assumption of the coincident operation of all solar and wind generators. EnergyAustralia requested that appropriate risk metrics and analysis be provided, including duration, weather sensitivities and other scenario analysis, in order to justify the target level of procurement, its associated expense and the expected risk to be borne by customers.	Our assumption regarding the coincident operation of solar and wind generators is considered necessary due to NEM-experience that these inverters remain online at night or during periods of low output and thus need to be kept stable. We note that this assumption is consistent with the approach taken by AEMO. We note that the industry is currently undertaking studies around the system strength requirements at varying assumed levels of generation output for these generators. We expect this will inform future approaches and assumptions regarding the assumed operation of these generators.

E.2 Scope of the network components

EnergyAustralia stated that it is unclear from the PSCR how Transgrid has determined the number and location of synchronous condensers relative to AEMO's declared shortfalls and IBR forecasts and consider there to be too many. They requested a demonstration of the scoping and timing of network solutions in the PADR, including how inter-regional relationships have been modelled and scale efficiency achieved and justified.[98]

Transgrid response: the assessment in this PADR has significantly refined the approach to determining how many synchronous condensers are expected to be required as part of each option. Specifically, the portfolio optimisation approach (described in section 4) has been used to determine how many synchronous condensers feed into each option and has resulted in significantly less synchronous condensers in all portfolio options than suggested as part of the PSCR.

E.3 Option value and the timing of options

EnergyAustralia consider that there could be material option value in the procurement of flexible non-network solutions, which are also likely to be less capital-intensive and ready for immediate deployment.

[98] EnergyAustralia, p. 5.

They also encouraged Transgrid to adopt a scenario-based approach for timing options around delivery of network solutions.[99]

Transgrid response: we agree that the procurement of flexible solutions (i.e., those that provide the ability to ramp up or down requirements as circumstances change) is expected to be important for this RIT-T given future uncertainty.

While each portfolio option is found to involve a number of flexible elements, 'option value' is not considered material for this RIT-T on account of only one scenario being considered relevant for the assessment (as outlined in section 8.1). Moreover, as outlined in section 8.1, we consider that each portfolio option exhibits the same approximate level of flexibility and so do not consider there to exist materially different levels of option value across the portfolios.

E.4 AEMO directions and involuntary load shedding under the base case

EnergyAustralia stated that it is not evident from the PSCR that the cost of AEMO directions (fuel use, etc) or the amount of lost load would result in 'astronomically' high benefits and that this should be validated in the PADR. EnergyAustralia requested that Transgrid clearly explain its approach to valuing AEMO directions under the base case, which would occur prior to any involuntary load-shedding, in the context of the dispatch profiles of plant operating in the market and unit commitment/decommitment profiles in its market modelling.[100]

Transgrid response: the wholesale market modelling captures the cost of AEMO directions under the base case (e.g., fuel costs, FOM and VOM) as it assumes these plant are directed to run. The various option cases then avoid these costs by being able to meet the required system strength requirements without the need for AEMO directions.

Under the base case, we would not meet the new requirements to provide a minimum and efficient level of system strength into the future. Under these conditions, it is expected that AEMO would direct existing synchronous generators to operate, where possible, to maintain system security. In the event that insufficient system strength is available as thermal generators retire or are unavailable, there is expected to be significant interruption of supply to loads in NSW under normal and contingency conditions. See section 5.5 for a further discussion of the base case and the approach to estimating avoided unserved energy in this PADR.

E.5 Treatment of non-network option costs

Origin Energy queried how the energy consumption of network-owned synchronous condensers will be treated and suggested that they may be treated as transmission losses. Origin Energy also stated that it is not clear that this would be the case for synchronous condensers owned and operated by non-network businesses such as a generator.[101]

Transgrid response: the wholesale market modelling treats the energy consumption of synchronous condensers as dispatchable loads, and dispatches additional generation to supply this demand. The cost of the synchronous condensers' energy consumption is thus accounted for in the fuel and VOM costs of this

[99] EnergyAustralia, pp. 5-6.
[100] EnergyAustralia, p. 5.
[101] Origin Energy, pp. 1-2.

additional generation dispatch. This approach is the same for both network and non-network owned synchronous condensers.

Origin Energy also stated that they consider it unclear as to how generators would be compensated for system strength operationally through a Transgrid contract and how energy consumed through the process of providing system strength would be treated for the following:[102]

- in-merit generators – a coal plant, for example, that is in merit and providing system strength as a by-product of energy;
- out-of-merit generators – a peaking gas plant, for example, that is out of merit but is enabled for system strength only; and
- a synchronous condenser owned by a generator – enabled for system strength and providing no other service.

Transgrid response: the specifics of how individual parties will be compensated for the provision of system strength is to be determined via the procurement process accompanying this RIT-T. In addition, as part of the regulatory framework developed under the 'improving security frameworks for the energy transition' rule change, the AEMC have stated that AEMO will only dispatch a 'gap' in system strength and therefore variable payments are likely to be only paid for the gap with any plant operating within the merit order not receiving variable payments.[103]

E.6 How inter-regional assets are assessed

Origin Energy requested information on how Transgrid will treat inter-regional solutions as part of this RIT-T. They stated that it is unclear if the RIT-T will make assumptions as to inter-regional asset availability or on the likelihood of future contracts with other transmission businesses.[104]

Transgrid response: system strength does not stop at state boundaries and some system strength naturally flows from interstate into NSW. If we do not account for some of this system strength, we will effectively over-procure system strength in NSW, leading to higher costs for consumers.

Since the PSCR was released, we consulted with AEMO and other SSSPs and it was agreed that:

- for the minimum level of system strength, SSSPs should rely on joint planning arrangements to account for all interstate system strength contributions (and consequently 'expect' a certain level flowing from interstate); and
- for the efficient level of system strength, SSSPs should *not* consider any benefit from interstate since it is not known when it will be scheduled (i.e. it may not be online all the time) and because it is not known which technologies will provide a stable voltage waveform (voltage support is more 'local' than fault current. i.e. stable voltage waveform support may not travel very far).

For the minimum level of system strength, we have also 'derated' the amount assumed to come from each state (beyond N-1) so that each state is not relying on the other states meeting their minimum requirements

[102] Origin Energy, p. 1.
[103] AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024*, Final Determination, 28 March 2024, p. 80.
[104] Origin Energy, p. 2.

in full (otherwise all states will be relying on each other and there will be a gap in what is provided). Additional detail on how this derating has been applied is covered in Baringa's market modelling report.

While we received two proposals from proponents of inter-state solutions, they have consequently been ruled out of the PADR assessment. This has been communicated to the proponents of these solutions.

EnergyAustralia requested an explanation of how the operation of different IBR technologies and forecasts of other generation and network investments interact, over time and over different locations (including in other jurisdictions), to affect waveforms as per AEMO's criteria and Transgrid's fault level projections.[105]

Transgrid response: all BESS included in the IBR forecasts are assumed to be grid-following and so do not assist with providing system strength under the base case. However, and as outlined in section 4.2, we have assumed that developers of the 'modelled' batteries in AEMO's IBR forecast would, acting reasonably, be willing to upgrade their batteries from grid-following to grid-forming, if Transgrid offered them a network support agreement that covers the incremental cost of doing so.[106] Section 9.7.1 also presents the results of a sensitivity test that assumes that all AEMO forecast BESS are grid-forming, resulting in less IBR to be remediated and a lower efficient level.

All grid-forming solutions are able to provide stable voltage waveform and their individual characteristics (including their location) affect how much they are able to provide.

E.7 Transparency regarding the modelling

EnergyAustralia has requested transparency on the treatment of:[107]

- the interactions between synchronous condensers and non-network solutions across different candidate portfolio options;
- how Transgrid will model the dispatch of different technologies including interactions with energy and ancillary services markets under the OSM;
- locational factors, including dispatchable unit identifier (DUID) level effects on system strength across nodes, and interstate interactions;
- the evolution of system strength needs at each node as new transmission investment is commissioned;
- the intraday shape and seasonality of system strength supply and demand over example reference years; and
- assumptions about motors (e.g. pumped hydro) providing fault current.

Transgrid response: Transgrid's portfolio formation methodology and, in particular, the approach for calculating and tuning system strength coefficients means that the interactions between different non-network and network solutions, locational factors and implications of transmission investment on system

[105] EnergyAustralia, p. 3.
[106] This approach was confirmed with AEMO as part of the SSSP working group in early 2023. AEMO also confirmed that assuming all batteries within the IBR forecast are grid-following is appropriate at this point in time. AEMO suggested that, over time. this may change (which would be reflected in different IBR forecasts) but at this stage it is preferable to be conservative regarding the assumed contribution from these BESS.
[107] EnergyAustralia, p. 6.

strength contributions have been specifically considered. More information can be seen in Appendix C and in Baringa's market modelling report.

EnergyAustralia also requested that, to the extent these are not reflected in the final 2023 IASR or Draft 2024 ISP methodology, Transgrid should explore credible sensitivities around:[108]

- Eraring's closure date;
- the commissioning of the CWO REZ infrastructure;
- Snowy 2.0;
- HumeLink;
- Sydney Ring projects; and
- VNI West.

Transgrid response: with the exception of Eraring's closure date which will be modelled as part of the RIT-T reopening trigger consultation, we have not investigated these sensitivities as part of the PADR and do not expect that they will change the key findings of the assessment. We may consider these further as part of the PACR if we consider any of them to be potentially material to the specific portfolio option preferred overall.

E.8 How the broader ongoing work program on system services will affect this RIT-T (and vice versa)

Origin Energy stated that it is not clear how projects that can contribute to system strength and other services such as inertia will be assessed against those that can only provide system strength.[109]

Transgrid response: as outlined in the box at the end of section 1.2, in March 2024, the AEMC announced the alignment of the new system strength rules with the inertia requirements so that TNSPs can co-optimise system strength requirements with inertia requirements.[110] While we do not consider that this RIT-T can realistically co-optimise across system strength and inertia due to these expected timings, we note that our requirements for high inertia synchronous condensers to provide effective stable voltage waveform support will mean that there are clear benefits for the provision of inertia.

EnergyAustralia raised a number of questions around system strength pricing in NSW.[111]

Transgrid response: we note that these points are separate to the RIT-T and have not been responded to as part of this PADR.

[108] EnergyAustralia, p. 7.
[109] Origin Energy, p. 2.
[110] AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024*, Final Determination, 28 March 2024, p iv, para 20.
[111] EnergyAustralia, p. 4.

E.9 Location of new system strength resources

Smart Wires suggests that REZ will provide suitable locations for siting the equipment that will provide the system strength services that will support the establishment of IBR generation in that area.[112]

Transgrid response: we agree that the optimal solutions will be at, or near, large groups of renewables (e.g., REZ). Section 5 summarises the locations of the key components in each portfolio option.

E.10 The use of MPFC technology

Smart Wires suggested that reducing the ‘electrical distance’ of the connecting network by series compensating the lines with an appropriate technology would allow the MW output of connecting IBR generators to increase since it would address the concerns of voltage magnitude regulation, voltage phase angle variation, voltage waveform distortion and voltage oscillations. Smart Wires stated that this would extend the reach of system strength services to a wider geographic area, increasing the potential to harness renewable energy resources at the most viable locations in rural NSW (which may be located remotely from a REZ or ‘strong’ part of the network).[113]

Smart Wires suggested that their form of series compensation – modular power flow control (MPFC) technology – could provide an economic means for a proposed renewable generator to increase the size of a wind or solar farm proposal, eliminating the need for providing their own system strength remediation in the form of a synchronous condenser.[114]

Transgrid response: while the Smart Wires solution can reduce line impedance in steady-state conditions, enabling other system strength solutions to increase their contribution, we do not believe it inherently provides stable voltage waveform support. In addition, we understand that existing Smart Wires devices are bypassed during faults to ensure correct protection operation, thus providing no improvement to fault levels during faults. Additionally, new sources of system strength can be strategically located near areas needing system strength support, limiting the benefit of reducing line impedance between solutions and the need. As such, at this stage, Transgrid has not considered a Smart Wires solution within this RIT-T.

[112] Smart Wires, p. 2.
[113] Smart Wires, p. 3.
[114] Smart Wires, p. 3.