People. Power. Possibilities.

Meeting system strength requirements in NSW

RIT-T Project Assessment Conclusions Report (PACR)

Region: New South Wales

Date of issue: 14 July 2025

Executive summary

Transgrid is responsible for ensuring sufficient system strength services are available to maintain the stability of the NSW power system. The forecast retirement of NSW coal generators in the coming decade (80% retiring by capacity) and the growth in inverter-based resources (IBRs) is driving an urgent need to add new sources of system strength.

A network without adequate system strength will result in stability issues and supply interruptions to end consumers. 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.

"The [AEMC Reliability] Panel emphasises the urgency of system security investment to keep pace with the transition... the Panel is of the view that to keep pace with the energy transition, security needs must be identified earlier so that timely investment can occur. Security risks are emerging faster than expected. For example, system strength and minimum system load have become critical risks earlier than expected, and market interventions have been needed to maintain system security."

"... the risks of over- and under-investment are asymmetric. The risk of over-investment in security services, or investment earlier than needed, comes with much lower costs than under-investment or investment that is too late. Under-investment could lead to periods when the NEM cannot be securely operated."

AEMC Reliability Panel, April 2025 [1]

New requirements apply for Transgrid as the System Strength Service Provider

As the System Strength Service Provider (SSSP) for NSW, Transgrid is applying the Regulatory Investment Test for Transmission (RIT-T) to assess options that meet our National Electricity Rule (NER) obligations. This refers specifically to clause S5.1.14 to deliver system strength services to the NSW power system to meet standards set by AEMO from 2 December 2025. The standards are designed to ensure the safe and secure operation of the power system ('minimum' level) and to facilitate the stable voltage waveform ('efficient' level) of new IBRs.

This RIT-T examines network and non-network solutions to comply with system strength requirements and to maximise net economic benefits to the National Electricity Market (NEM) and ultimately to consumers.[2]

The PACR has benefited from stakeholder consultation

Publication of this PACR is the final stage of the RIT-T process. It follows publication of the Project Specification Consultation Report (PSCR) in December 2022, the Project Assessment Draft Report (PADR) in June 2024 and the PADR Supplementary Report in October 2024.

[1] AEMC Reliability Panel, 23 April 2025, Letter to AEMO: Reliability Panel comments on AEMO's Transition Plan for System Security

[2] 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., Clause S5.1.14 of the NER.

The analysis has been strongly informed by stakeholder consultation, and we thank all parties for their valuable input throughout this RIT-T. We received eight stakeholder submissions over the course of the RIT-T and engaged in Joint Planning activities with AEMO, other SSSPs, Ausgrid and EnergyCo.

The PACR refines PADR inputs and assumptions using latest information

The overall characterisation of the identified need has not changed since the PADR and the PADR Supplementary Report. The PACR refines and updates assumptions and approaches to reflect latest information, including:

- updated delivery dates for the New England REZ Network Infrastructure project;
- updates to the Hunter-Central Coast REZ Network Infrastructure project being delivered by Ausgrid;
- revised delivery schedule for Central West Orana REZ synchronous condensers to align with a schedule provided to Transgrid by EnergyCo;
- a new sensitivity on the revised timing and quantum of IBR within the South West REZ, aligned to the recently awarded Access Rights to 4.3 GW of IBR capacity;
- updated information on each individual non-network solution, including Transgrid's assessment of technical and commercial feasibility of each non-network solution;
- independent assessment by GHD of the technical feasibility and implication of additional hours of operation of NSW hydro and gas units for system strength provision;
- advanced investigations of network (Transgrid) synchronous condenser costs, lead-times and market capacity through market sounding of suppliers and site assessments; and
- PSCAD studies of grid-forming Battery Energy Storage Systems (BESS), including all major suppliers, to further assess their ability to provide stable voltage waveform support.

The PACR has assessed more than 100 individual solutions

Transgrid undertook an EOI for system strength services from third-party proponents (i.e. entities that could provide system strength services to Transgrid under a non-network system security contract). Transgrid received submissions from 30 parties, covering over 60 individual potential solutions, including:

- > 14 GW of existing or modifications of existing synchronous generators;
- > 3 GW of other new generation and energy storage projects, including pumped hydro, gas and compressed air storage;
- > 7.5 GW of grid-forming BESS; and
- several non-network synchronous condensers.

Transgrid has also assessed 46 additional individual solutions including grid-forming BESS and synchronous condensers in network locations identified as optimal for system strength provision.

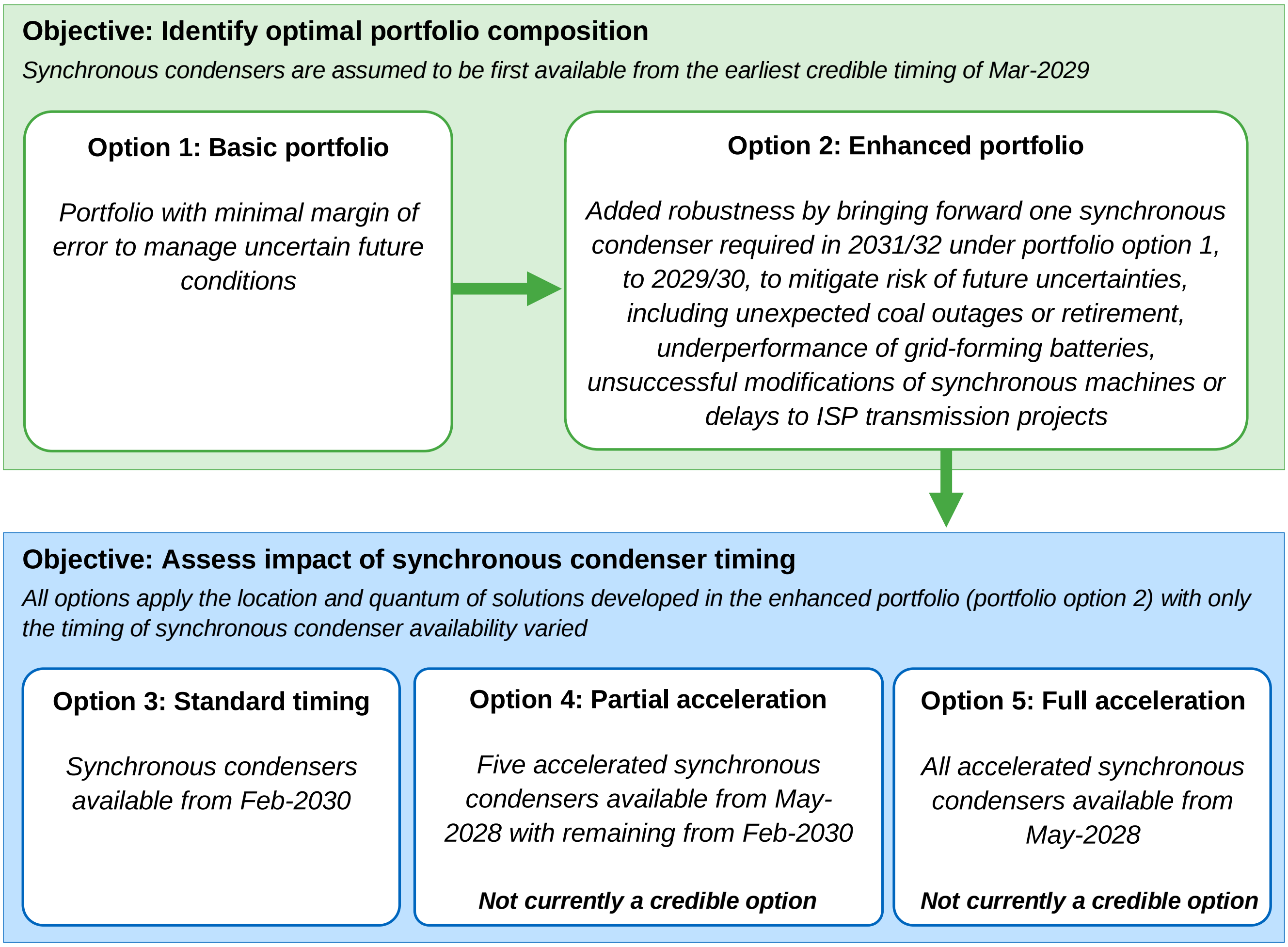
Five portfolio options have been assessed in this RIT-T

In light of the scale of NSW's system strength requirements, the objective of the PACR was to identify an optimal 'portfolio option' (being a portfolio of individual system strength solutions) which met our requirements while maximising the present value net market benefits.

Different portfolio options were then created by varying the assumed timing of synchronous condensers.

Currently, only portfolio options 1, 2 and 3 are credible as portfolio options 4 and 5 assume synchronous condensers are available earlier (May 2028) than considered credible. Transgrid identified the credible timing synchronous condensers are first available is between March 2029 and February 2030. The range of credible timing reflects uncertainty in factors external to Transgrid, including the lead-time of synchronous condensers, the regulatory approval process with the Australian Energy Regulator (AER) and the dispute process for this PACR. In all portfolio options, the delivery of each subsequent synchronous condenser is staggered by 1.5-months.

Figure 1. Summary of portfolio options in this PACR [3]



Portfolio options 4 and 5 are only expected to be credible if Transgrid commences procurement of synchronous condensers before the AER's approval of a Contingent Project Application. However, insights from our market modelling show that if these two options were proven to be credible, there would be significant additional net market benefits.

[3] Portfolio option 1 of the PACR follows the same methodology as portfolio option 1 of the PADR which was considered the most credible option for the PADR. The names of the other portfolio options for the PACR do not link to the names used in the PADR.

Portfolio options share key themes

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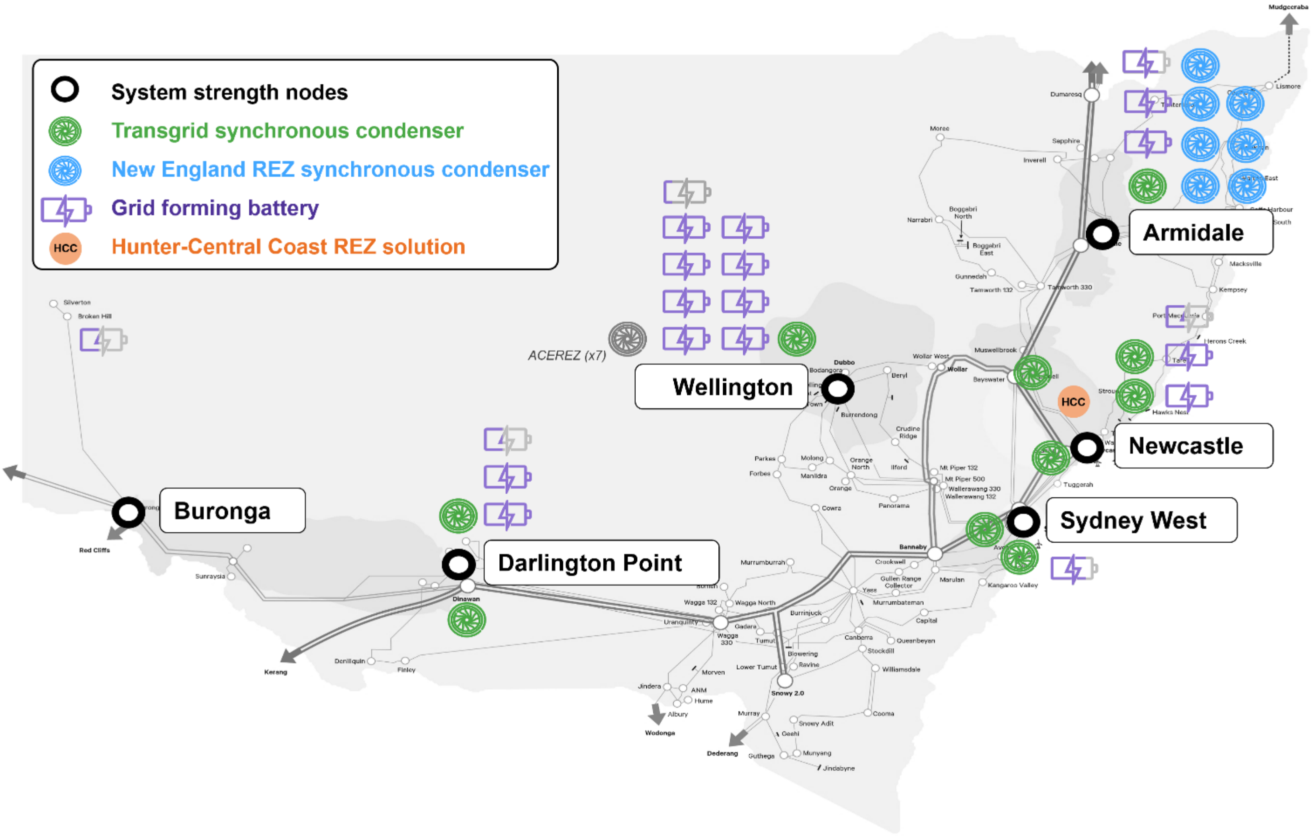
Portfolio options share key themes, including:

- new sources of system strength are needed rapidly to replace retiring coal units;
- 're-dispatch' (increase in operating hours) of synchronous generators (hydro, gas, coal) is important in the next five years before new system strength solutions come online;
- grid-forming batteries are a cost-effective source of system strength to facilitate renewable generation when already committed for energy market purposes; and
- once deployed, grid-forming batteries and synchronous condensers form the core solution set to meet medium to long-term system strength needs.

A geographic representation of new-build system strength solutions[4] in portfolio option 2 (preferred credible option) is presented in Figure 2, broadly grouped by system strength node.

Figure 2. Indicative map of new-build system strength solutions in portfolio option 2 (where each grid-forming battery icon represents the equivalent contribution to the efficient level of system strength as one synchronous condenser)



Network (Transgrid) synchronous condensers include remediation for the South West REZ. Synchronous condensers required for the New England REZ may be delivered by a third-party network operator and solutions for Hunter-Central Coast REZ will be procured as non-network solutions (discussed below).

[4] excluding upgrades to synchronous machines for commercial sensitivity.

New build system strength solutions

Table 1 presents the composition and timing of each portfolio option.

- Portfolio option 1 ('basic portfolio') has been formed through a market and power system modelling co-optimisation to meet energy market and system strength needs in NSW. The output produces a portfolio of system strength solutions which has minimal margin of error to manage uncertain future conditions;
- Portfolio option 2 ('enhanced portfolio') brings forward one synchronous condenser identified as required in 2031/32 in portfolio option 1, to 2029/30. This adjustment adds robustness to the portfolio to mitigate risks related to future uncertainties on the availability of system strength in NSW; and
- Portfolio options 3 – 5 vary the timing of network synchronous condensers to identify the optimal timing of Transgrid synchronous condensers. The composition of the portfolio of solutions is identical to portfolio option 2.

Table 1. New-build solutions for each portfolio option

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050MVA fault current), see note 1									
Portfolio 1	-	-	-	3	9	9	9	9	9
Portfolio 2	-	-	-	3	10	10	10	10	10
Portfolio 3	-	-	-	-	4	10	10	10	10
Portfolio 4	-	-	2	5	9	10	10	10	10
Portfolio 5	-	-	2	9	10	10	10	10	10
New England REZ synchronous condensers Cumulative number of units (each providing 1,050MVA fault current), see note 2									
Portfolio 1	-	-	-	-	-	-	6	8	8
Portfolio 2 - 5	-	-	-	-	-	-	5	7	7
Upgrades to synchronous machine to allow synchronous condenser mode Cumulative capacity (MW)									
All portfolios	50	50	300	650	650	650	650	650	650
Grid-forming BESS Cumulative capacity (MW)									
All portfolios	-	1,350	3,250	3,650	4,150	4,800	4,800	4,950	8,150

Note 1: If synchronous condensers with a fault level contribution of <950MVA are selected through Transgrid's procurement process (calculated using unsaturated reactance), an additional one synchronous condenser is required between 2028/29 and 2030/31 in the Sydney West or Newcastle region (date is unique to each option).

Note 2: Solutions for New England REZ are separately itemised as EnergyCo may adopt an approach outside of the NER framework, where central system strength remediation is the responsibility of a third-party network operator (rather than Transgrid as the SSSP for NSW). Transgrid will not progress the procurement of solutions for New England REZ until EnergyCo's approach has been confirmed.

Table 1 excludes:

- New build solutions for Hunter-Central Coast REZ. Solutions are required from 2027/28, being either four smaller non-network synchronous condensers (275 MVA fault level each) or 200 MW of non-network grid-forming batteries. Non-network solutions were not able to be fully assessed given arrangements for the distribution-connected REZ were only recently announced. Transgrid will carry out a procurement process to identify the preferred solution and proponent; and
- Seven synchronous condensers being deployed in Central West Orana REZ by ACEREZ, as these are outside the scope of this RIT-T (see Section 2.3.5.1 for detail).

Our modelling identifies that 5 GW of grid-forming batteries (by 2032/33) provides the equivalent stable voltage waveform support as approximately 17 synchronous condensers. We expect the 5 GW of grid-forming BESS will contribute to growing confidence in the technology to support system strength and enable testing to potentially contribute to the minimum level of system strength over time.

Costs of the portfolio of system strength solutions

Given the magnitude of the identified need, there are significant costs across all portfolio options. We estimate total capital and operating costs for the full 20-year horizon to 2044/45 for the preferred credible portfolio option 2 as (undiscounted 2023/24 dollars):[5]

Network (Transgrid) costs include:

- $1,608 million capital costs and $157 million operating costs for new synchronous condensers.

New England REZ synchronous condenser costs (proponent to be identified by EnergyCo):

- $1,077 million capital costs and $89 million operating costs for REZ synchronous condensers.

Non-network costs include:

- $181 million capital costs and $18 million operating costs for system strength solutions for the Hunter-Central Coast REZ;
- $18 million capital costs and no incremental operating costs for upgrades to existing and new synchronous generators to enable synchronous condenser capability; and
- $2,644 million capital costs and $476 million operating costs for grid-forming BESS including new-build and upgrades of committed/anticipated and ISP-modelled solutions to enable grid forming capability.

Table 2 summarises the total capital and operating costs for each portfolio option over the full 20-year assessment period, excluding re-dispatch costs. Section 5 explains the cost assumptions.

[5] All costs in the PACR are presented in 2023/24 dollars unless otherwise specified. 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). Costs exclude re-dispatch costs.

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

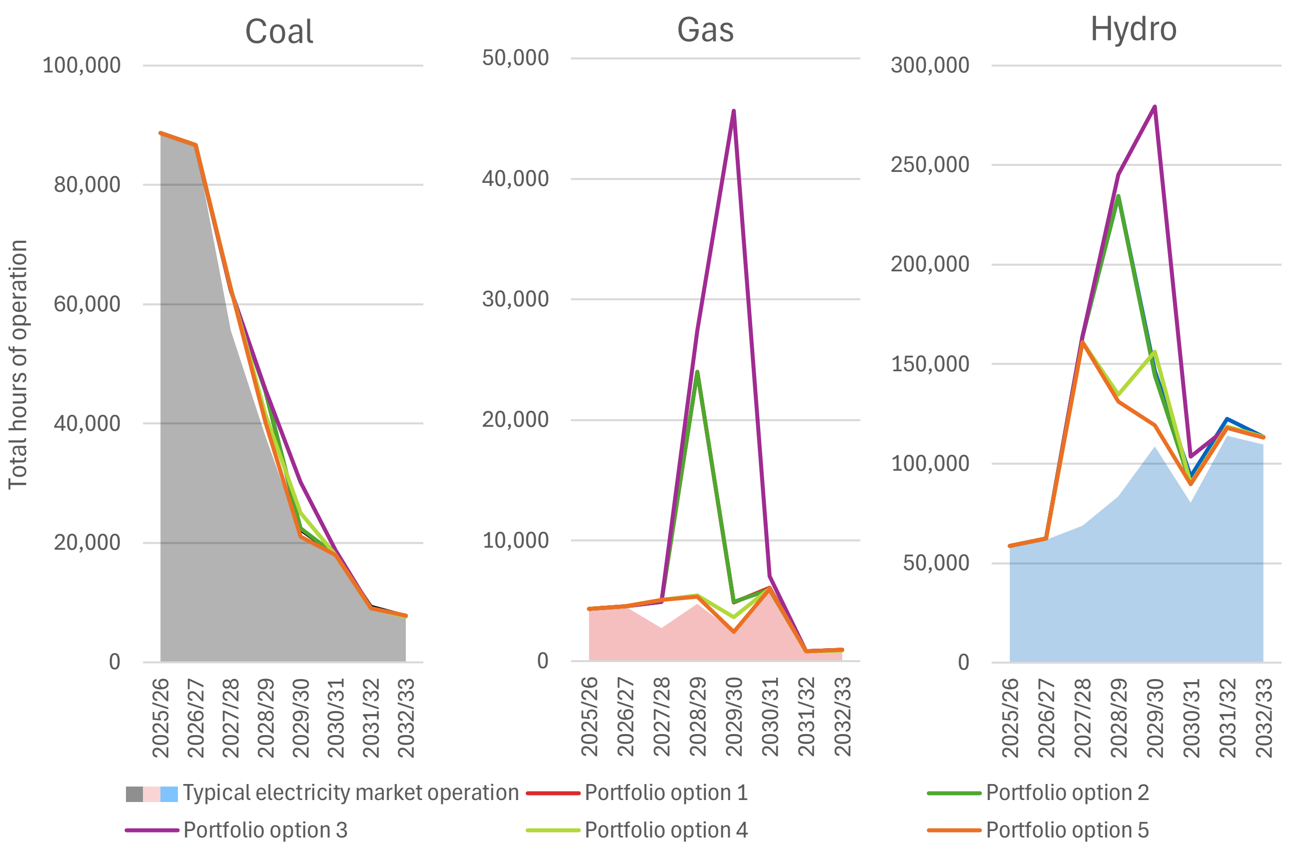
	Portfolio option 1	Portfolio option 2	Portfolio option 3	Portfolio option 4	Portfolio option 5
Capex $m	5,511	5,528	5,528	5,528	5,528
Opex $m	737	740	732	743	748
Total $m	**6,248**	**6,269**	**6,260**	**6,271**	**6,276**

Non-network solutions will be enabled via non-network system security contracts with Transgrid. Contract costs are treated as a wealth transfer under the RIT-T (and have no bearing on the Net Present Value (NPV) results),[6] however are expected to have a material impact on the ultimate cost to end consumers.

Re-dispatch of synchronous generators is vital over the next five years

'Re-dispatch' (increase in operating hours compared to typical market operations) of synchronous generators is a critical part of all portfolio options to meet the minimum level of system strength before synchronous condensers are available. Total hours of operation for each portfolio option are shown in Figure 3 (lines), compared with typical hours of operation modelled for electricity market purposes only (shaded area).

Figure 3. Re-dispatch of synchronous machines across all portfolio options to 2032/33



[6] AER, October 2023, Regulatory investment test for transmission – application guidelines (Final decision)

All portfolio options rely on some hydro re-dispatch to meet needs in the first two years (no coal or gas re-dispatch). Portfolio options 4 and 5 exhibit materially lower re-dispatch in 2028/29 and 2029/30 because of the earlier deployment of synchronous condensers.

Portfolio options 1 - 3 rely heavily on gas re-dispatch to meet the need in years 2028/29 and 2029/30. Transgrid's market modelling includes a daily NEM-wide gas constraint (consistent with AEMO's 2024 ISP) and a specific additional pipeline constraint for two NSW gas generators (consistent with GHD advice). However, a comprehensive assessment of gas pipeline capacity and gas supply availability was out of scope for this assessment. As such, modelling may over-estimate the possible re-dispatch of gas, which may result in an underestimate for forecast risks of system strength gaps.

Accelerated deployment of synchronous condensers reduces the risk of gaps in system strength

Modelling for each portfolio option identifies the risk of gaps to the minimum level of system strength. The risk of gaps occurs before synchronous condensers can be sufficiently deployed, as shown in Table 3. Risks are highest during periods of co-incident generation maintenance or forced outages.

Table 3. Years where the risk of system strength gaps occur for portfolio options 1 - 5

	Portfolio option 1	Portfolio option 2	Portfolio option 3	Portfolio option 4	Portfolio option 5
2025/26	No gaps	No gaps	No gaps	No gaps	No gaps
2026/27	No gaps	No gaps	No gaps	No gaps	No gaps
2027/28	Risk of gaps	Risk of gaps	Risk of gaps	Risk of gaps	Risk of gaps
2028/29	Risk of gaps	Risk of gaps	Risk of gaps	No gaps	No gaps
2029/30	No gaps	No gaps	Risk of gaps	No gaps	No gaps
2030/31	No gaps	No gaps	No gaps	No gaps	No gaps
2031/32	No gaps	No gaps	No gaps	No gaps	No gaps
2032/33	No gaps	No gaps	No gaps	No gaps	No gaps

Risks of gaps in the minimum level of system strength are projected to occur for:[7]

- up to 2% of time in 2027/28 across all portfolio options after the closure of Eraring Power Station;
- up to 1.5% of time in 2028/29 for portfolio options 1 – 3 at all nodes other than Armidale, and up to 10% of time at Armidale; and
- up to 5% of time in 2029/30 for portfolio option 3 at all nodes other than Armidale, and over 20% of time at Armidale.

Risks of gaps during critical planned outages may be partially mitigated if transmission outages can be co-ordinated with periods of high coal generation availability.

Transgrid is working to enable earlier procurement and installation of synchronous condensers to minimise power system security risks. In the operational timeframe, Transgrid will support AEMO and other relevant parties to manage the risks of insufficient system strength.

[7] Note that the assessment of risks of gaps in system strength is subject to market modelling assumptions. Gaps may be more or less in reality.

Portfolio option 2 is the preferred credible option

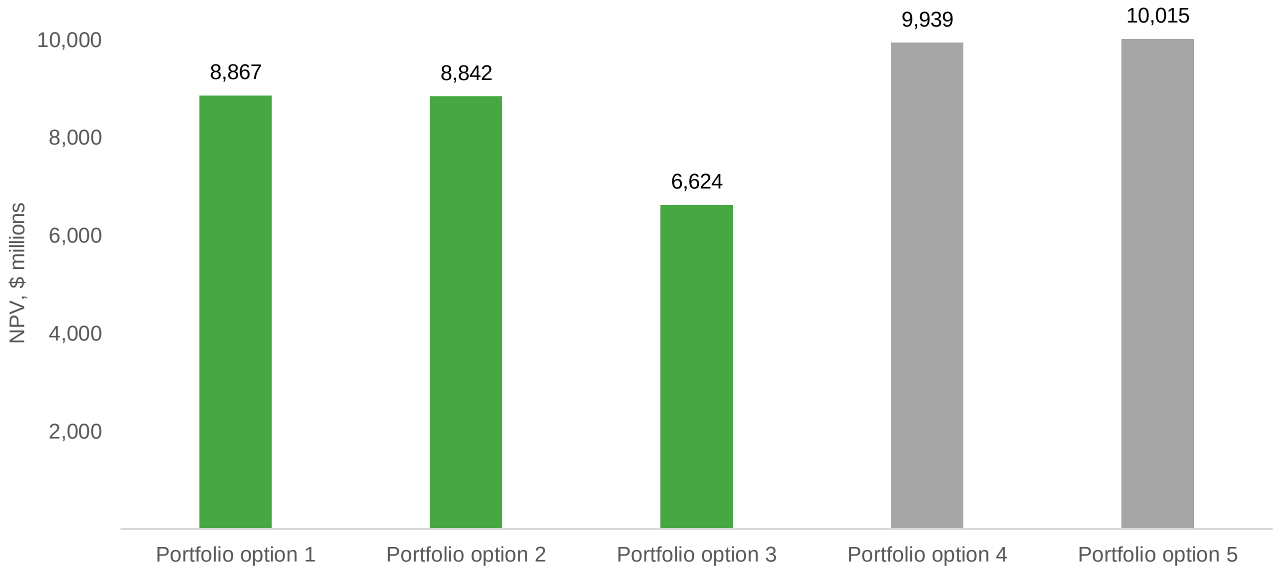
Figure 4 summarises the headline NPV results for each portfolio option. All portfolio options are found to generate substantial net market benefits over the assessment period – at least $6.6 billion in net benefits, in present value terms.[8] These benefits are primarily attributable to:

- avoided gaps in system strength (and therefore avoided unserved energy); and
- avoided generator fuel costs and lower emissions associated with lower re-dispatch of synchronous machines.

Portfolio options 1, 2 and 3 are the credible portfolio options identified in this PACR:

- portfolio options 1 and 2 are within a margin of error (difference in net market benefits of $25 million or 0.28% and a difference in total portfolio capital costs of $21 million or 0.33%); and
- portfolio option 3 has the lowest net benefits due to the delay in synchronous condenser delivery ($2.2 billion lower than portfolio option 2).

Figure 4. Headline NPV results for portfolio option 1 – 5; green indicates currently credible portfolio options; grey indicates a portfolio option that is not yet credible, but would deliver additional market and consumer benefits



The enhanced portfolio (portfolio option 2) provides increased resilience to the NSW power system by bringing forward one synchronous condenser identified as required in 2031/32 in portfolio option 1, to 2029/30. Increased resilience would support power system security in situations such as more significant generator unplanned outages or longer than expected maintenance, earlier coal retirements, higher-than-expected IBR deployment, delays to contracting with or availability of non-network solutions or delays to ISP transmission projects such as HumeLink, Hunter Transmission Project or VNI West.

The net market benefits of the basic portfolio (portfolio option 1) and enhanced portfolio (portfolio option 2) are very similar; the difference between the two is within the margin of error for the assessment. This

[8] Note that 'at least' is used here and throughout the report when discussing the headline net market benefits. This is on account of the approach taken to remove the avoided unserved energy that is common to all option portfolios from the assessment, as it does not assist with ranking the portfolio options (as discussed in Appendix F.3 now). If this unserved energy is added to the analysis, the expected net benefit of all portfolio options would be significantly greater.

justifies bringing forward one synchronous condenser earlier in the assessment period to increase the resilience of the portfolio to different states of the world relative to the assumptions modelled. As such, the enhanced portfolio (portfolio option 2) is considered the preferred credible option for this RIT-T.

Accelerating synchronous condensers will deliver materially more market benefits

Portfolio options 4 and 5 are not currently credible. However, if the accelerated procurement of Transgrid synchronous condensers is confirmed as credible, this would lead to higher net market benefits, specifically:

- a $3.3 billion increase in net market benefits when five network synchronous condensers are accelerated (portfolio option 4 compared to 3), or $1.1 billion compared to portfolio option 2; and
- a $3.4 billion increase in net market benefits when ten network synchronous condensers are accelerated (portfolio option 5 compared to 3), or $1.2 billion compared to portfolio option 2.

Earlier deployment of synchronous condensers also delivers a more resilient power system and enables earlier achievement of 100% instantaneous renewables in NSW, which supports government emissions reduction goals.

Full acceleration of network synchronous condensers (portfolio option 5) has $76 million higher net market benefits than partial acceleration (portfolio option 4). Transgrid expect the difference in net market benefits to be larger in reality as portfolio option 5 is more resilient to a range of plausible events including more significant generator unplanned outages or maintenance, earlier coal retirements, higher than expected IBR deployment, delays to contracting with or availability of non-network solutions or delays to ISP transmission projects such as HumeLink, Hunter Transmission Project or VNI West.

Two case studies indicate additional net market benefits of portfolio option 5 (not included in Figure 4), including:

- if the timing of South West REZ IBR build-out is consistent with advice from EnergyCo, portfolio option 5 has an additional $20 million benefits relative to portfolio option 4; and
- added resilience benefit to manage risk of delays to major transmission projects. For example, if the Hunter Transmission Project was delivered two years later than assumed in AEMO's 2024 Integrated System Plan, portfolio option 5 has an additional $30 million benefits relative to portfolio option 4.

Providing resilience to future uncertainties is consistent with the AEMC Reliability Panel's view[9] on the asymmetric risk of early or late-investment in system strength (or over and under-investment), as quoted: *"the risks of over- and under-investment are asymmetric. The risk of over-investment in security services, or investment earlier than needed, comes with much lower costs than under-investment or investment that is too late. Under-investment could lead to periods when the NEM cannot be securely operated."*

In recognition of the urgency of system strength requirements, Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders to enable the regulatory and procurement process to progress as quickly as possible. Following publication of the PACR, Transgrid will continue this work to

[9] AEMC Reliability Panel, 23 April 2025, Letter to AEMO: Reliability Panel comments on AEMO's Transition Plan for System Security *and* AEMC, 2021, Final Rule: Efficient management of system strength on the power system

deliver Transgrid synchronous condensers as soon as possible, with the goal to reduce power system security risks and maximise net market benefits.

Next steps

This PACR is the final stage in the RIT-T process.

Portfolio option 2 is currently the preferred credible portfolio option. It would be replaced as the preferred option by portfolio option 4 or 5 if the accelerated procurement of synchronous condensers became credible.

Parties wishing to raise a dispute notice with the AER may do so prior to 18 August 2025 (30 days after publication of this PACR). Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au.

Transgrid will commence procurement and regulatory processes for individual solutions identified by the preferred portfolio of system strength solutions, including:

- network solutions (synchronous condensers): Transgrid will submit a contingent project application to the AER once all triggers have been met; and
- non-network solutions: Following procurement processes, Transgrid will assess whether the non-network solutions meet criteria for efficient and prudent expenditure. For eligible contracts, Transgrid will seek a determination from the AER and, when successful, will execute with proponents.

Future system strength requirements will continually change, including due to revised IBR forecasts within AEMO's annual System Strength Report. Transgrid will use non-network solutions to provide flexibility in how the preferred portfolio of solutions identified through this RIT-T meets the evolving needs of the NSW power system.

Contents

Sensitive

Acronyms

Acronym	Meaning
AACE	American Association of Cost Engineering
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
CPA	Contingent Project Application
DNSP	Distribution Network Service Provider
EMT	Electromagnetic Transient
EOI	Expression of Interest
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
FOM	Fixed Operation and Maintenance
GFM	Grid-forming
IASR	Inputs, Assumptions and Scenarios Report
IBR	Inverter-based resources
ISP	Integrated System Plan
MCC	Material Change in Circumstance
MCE	Ministerial Council on Energy
NEM	National Electricity Market
NER	National Electricity Rules
NEO	National Electricity Objective
NMAS	Non-Market Ancillary Service
NSCAS	Network Support and Control Ancillary Services
NSW	New South Wales
NPV	Net Present Value
OFS	Option Feasibility Studies
ODP	Optimal Development Path
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
REZ	Renewable Energy Zone
RFT	Request for Tender
RIT-T	Regulatory Investment Test for Transmission

Acronym	Meaning
RMS	Root Mean Square
SRAS	System Restart Ancillary Services
SSMR	System Strength Mitigation Requirement
SSSP	System Strength Service Provider
STATCOM	Static Synchronous Compensators
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability
VOM	Variable Operational and Maintenance
VER	Value of Emissions Reduction
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

Disclaimer

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1. Introduction

A new system strength framework was introduced in 2021, following the Australian Energy Market Commission's (AEMC) 'Efficient management of system strength on the power system' rule change[10]. Under the new framework Transgrid, as the System Strength Service Provider (SSSP) for NSW, is responsible for planning to ensure there is sufficient system strength available in the NSW power system to meet the standard set by the Australian Energy Market Operator (AEMO), as outlined in their annual System Strength Report.

Transgrid is applying the Regulatory Investment Test for Transmission (RIT-T) to portfolio options that meet system strength requirements in the New South Wales (NSW) power system. This RIT-T examines network and non-network solutions to ensure compliance with system strength requirements in the National Electricity Rules (NER) and provide the greatest net market benefit to the energy market and ultimately to consumers. The options assessed represent portfolios of network and non-network solutions, rather than options with a single solution, reflecting the scale and geographical breadth of the identified need.

Publication of this Project Assessment Conclusions Report (PACR) represents the final stage of the RIT-T assessment and consultation process (outlined in Figure 5). It follows the Project Assessment Draft Report (PADR) released in June 2024 and PADR Supplementary Report released in October 2024.

1.1. Purpose of this report

The purpose of this PACR is to:

- update the description of the identified need and outline developments since the publication of the PADR and PADR Supplementary Report (this has been included within the chapter summary for each section and Appendix H details the changes to the portfolio options);
- summarise points raised in submissions to the PADR and PADR Supplementary Report and highlight how these have been addressed in the PACR analysis;
- describe the options being assessed in this PACR, including the options proposed by non-network proponents and how these have been combined (together with potential individual network solutions) into 'portfolio options';
- describe the technical and commercial feasibility assessment conducted for both network and non-network solutions;
- present the results of the net present value (NPV) analysis for each of the portfolio options;
- describe the key drivers of the NPV results, as well as the assessment that has been undertaken to ensure the robustness of the conclusion;
- identify the overall preferred portfolio option to meet the identified need; and
- set out the re-opening triggers, building on the sensitivity assessments undertaken and the triggers presented in the PADR, to provide transparency to stakeholders on what will constitute a later material change in circumstance for this RIT-T.

[10] AEMC, 21 Oct 2021, Efficient management of system strength on the power system (Final determination)

Transgrid is also publishing the following documents alongside the PACR:

- Baringa Market Modelling Report, providing additional information on the market modelling methodology and assumptions underpinning this RIT-T; and
- detailed NPV benefits workbook.

1.2. Next steps

Publication of the PACR represents the final stage of the RIT-T process. Parties wishing to raise a dispute notice with the AER may do so prior to 18 August 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude.

Following the conclusion of this RIT-T (or in parallel as appropriate), Transgrid will commence procurement and regulatory processes for individual solutions required as part of the preferred portfolio of system strength solutions, including:

- network solutions (Transgrid synchronous condensers): The 'efficient management of system strength' final determination deems a system strength project proposed to be undertaken by a SSSP in its next current regulatory period (2023 - 2028 for Transgrid) to be a contingent project for the purposes of its revenue determination for that period.[11] A key next step is to submit a contingent project application to the AER once all triggers have been met.
- non-network solutions: The final portfolio of solutions in the PACR determines which non-network proponents or types of non-network solutions are eligible to participate in the procurement process. Following the procurement process, for eligible contracts Transgrid may seek a determination from the AER on whether Transgrid's proposed expenditure on non-network solutions meet criteria indicating efficient and prudent expenditure. If successful, this will be followed by the execution of non-network system security contracts between Transgrid and proponents.

The optimal composition of our portfolio of system strength solutions identified in our PACR is driven through a techno-economic co-optimisation of network and non-network solutions, including synchronous machines and grid-forming batteries, using best available information at the time of analysis.

Noting that future system strength requirements will change on a yearly basis as AEMO updates the IBR forecast in its annual System Strength Report, Transgrid intends to use non-network solutions to provide flexibility in how the preferred portfolio of solutions identified through this RIT-T meets these evolving needs in the coming years. Specifically, the portfolio options assessed in this RIT-T all involve the flexibility to be able to ramp up/down the provision of system strength due to the:

- scale of the portfolio of individual solutions;
- modulatory of solutions (both network and non-network); and
- ability to enter into short term non-network system security contracts, as required.

[11] AEMC. 2021, System Strength final determination

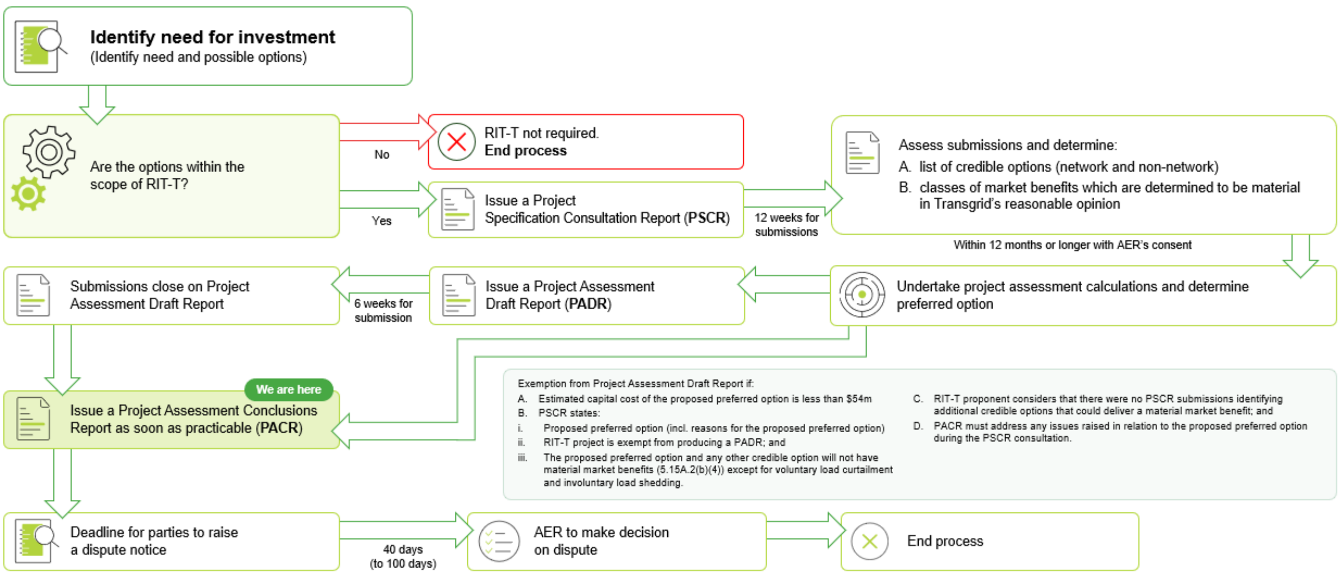
Due to the dynamic drivers of system strength needs, Transgrid will use the outcome of this RIT-T in terms of non-network solutions to identify the type of solutions that we should contract with (as well as establishing broad requirements for quantum and timing). However, during the ongoing procurement process for system strength, Transgrid will use the best information available to determine the specific location, amount and timing of non-network solutions to contract with.

As such, while we may need to commence a new system strength RIT-T in the coming years if there is a significant change in the requirements relative to what has been catered for in this RIT-T, we do not expect to commence a new system strength RIT-T immediately after finishing this RIT-T.

Consistent with the earlier 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. This has formed the basis for re-opening triggers which were consulted on during the PADR and expanded upon in this PACR. Many of the triggers are underpinned by analysis presented in this PACR, to demonstrate the intended change to the preferred portfolio option if this trigger does occur. This can inform a decision to change the preferred portfolio option and may avoid re-doing the entire RIT-T assessment (which would require significant time to complete and could jeopardise Transgrid's ability to provide an adequate amount of system strength at the required time).

Further details in relation to this project can be obtained from our regulation team via regulatory.consultation@transgrid.com.au.[12] In the subject field, please reference 'Meeting system strength requirements in NSW RIT-T PACR'.

Figure 5. Flowchart of the RIT-T process



[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.

2. The identified need

Chapter summary

System strength is a fundamental service required for the power system to operate in a secure state. The power system has historically had sufficient levels of system strength, provided by synchronous machines (such as coal, gas and hydro generators) as a by-product of their normal operation in the electricity market. The increasing penetration of inverter-based resources (IBR) and retirement of 80% of the NSW coal fleet over the coming decade requires urgent procurement of new system strength assets and services to ensure power system stability and to enable the connection of more IBR.

As the SSSP for NSW, Transgrid seeks to make sufficient system strength available to ensure the safe and secure operation of the power system ('minimum' fault level) and to facilitate the stable voltage waveform ('efficient' level) of new IBRs. This RIT-T is a 'reliability corrective action', as the portfolio options considered are for the purpose of meeting externally imposed regulatory obligations and service standards, as specified in Clause S5.1.14 of the NER.

While the overall characterisation of the identified need for this RIT-T has not changed since the PADR, the detail regarding the amount of system strength required, and the supporting assumptions, have been refined and updated to reflect latest information. For example, Transgrid has applied an IBR forecast developed by Baringa Partners ('Baringa'), rather than AEMO, to reflect latest available information on the delayed delivery date of New England REZ. This approach has the support of AEMO.

The minimum fault level requirements are unchanged since the PADR and are consistent with AEMO's 2024 System Strength Report.

Key changes from the PADR and PADR Supplementary Report

- AEMO announced the system strength shortfall previously identified between July and December 2025 has been deferred until 2027/28, due to the delayed retirement of Eraring Power Station;
- Transgrid has updated its efficient level requirements using an IBR forecast developed by Baringa. The forecast incorporates the delayed timing of the New England REZ transmission infrastructure project, which was not included in AEMO's 2024 System Strength Report (and has a material impact on the timing and distribution of forecast IBR uptake);
- IBRs which have elected to self-remediate their system strength impact have been removed from the IBR forecast. An assumption on the level of future battery energy storage system (BESS) projects that will self-remediate was applied based on industry trends, which further reduced the efficient level system strength need;
- we have revised the delivery schedule for synchronous condensers intended to remediate the Central West Orana REZ Stage 1 (5.84 GW of IBR) via ACEREZ, as formally advised by EnergyCo; and
- we have incorporated the latest information on the Hunter-Central Coast REZ in all portfolio options, and incorporated recently awarded Access Right recipients in the South West REZ via a sensitivity.

As the SSSP for NSW, Transgrid must proactively ensure there is sufficient system strength available, as specified by AEMO under NER Clause S5.1.14, to ensure the safe and secure operation of the power system ('minimum' level) and to facilitate the stable voltage waveform ('efficient' level) of new IBRs.

As outlined in the PSCR and the PADR, we consider this a 'reliability corrective action' RIT-T, as the portfolio options considered are for the purpose of meeting externally imposed regulatory obligations and service standards, i.e., Clause S5.1.14 of the NER.

This section outlines the need to procure system strength and the key developments which have occurred since the PADR and PADR Supplementary Report that have changed the assumptions underpinning the amount of system strength Transgrid is seeking to procure.

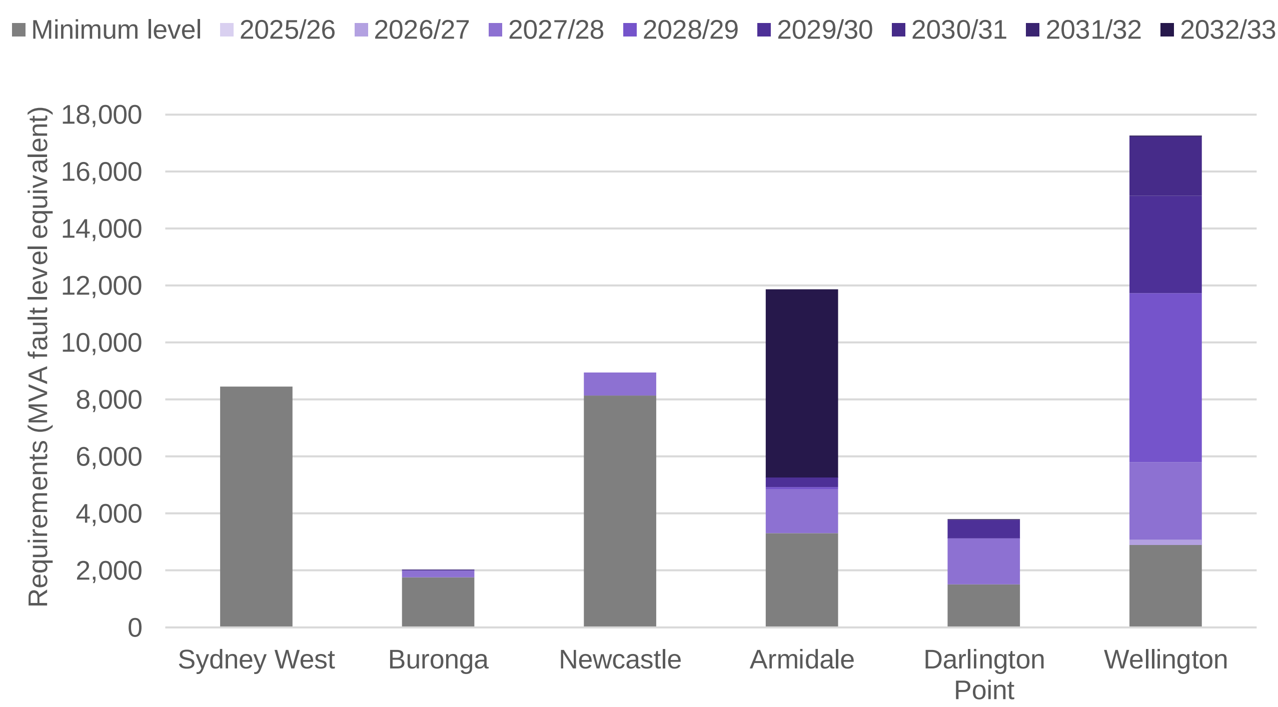
2.1. Transgrid's system strength obligations

Clause S5.1.14 of the NER requires that a Transmission Network Service Provider who is a SSSP (e.g. Transgrid) 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.

Figure 6 presents system strength requirements in NSW across the six system strength nodes, with the Available Fault Level (AFL) method used as a proxy for stable voltage waveform requirements.

Figure 6. Indicative view of system strength requirements in NSW to 2032/33 (purple represents efficient level requirements)



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. 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.

Coal generators currently contribute most of the system strength in NSW, provided as a byproduct of their electricity production. Renewable generators, which typically have grid-following inverters as their grid interface, require a strong voltage waveform (or heartbeat) to remain connected and to continue to generate electricity following a power system disturbance.

As coal generators progressively retire and new renewables continue to connect, Transgrid must urgently add new sources of system strength to the power system.

Minimum three phase fault level

A minimum amount of fault level (system strength) is required to ensure that protection systems operate correctly, and voltages stay within acceptable levels. Three phase fault levels are used to define minimum system strength requirements, measured in MVA fault level at the system strength nodes in NSW. Fault levels must be maintained above these minimum requirements, during system normal and following a credible contingency on the power system (e.g. a coal generator or transmission line trip). AEMO's minimum fault level requirements for NSW nodes are shown in Table 4.

Table 4. NSW minimum fault level requirements as per AEMO's 2024 System Strength Report

Node	System strength requirement (fault level, MVA)	
	Pre-contingency	Post-contingency
Armidale 330 kV	3,300	2,800
Buronga 220 kV	1,755	905
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

Stable voltage waveforms

SSSPs must use reasonable endeavours to provide sufficient system strength to support the level and type of IBR forecast by AEMO, such that:

(i) *in steady state conditions, inverter-based resources and market network service facilities do not create, amplify or reflect instabilities;*

(ii) *avoiding voltage waveform instability following any credible contingency event described in clause S5.1.2.1 or any protected event is not dependent on any of the inverter-based resources or market network service facilities disconnecting from the power system or significantly varying the active power or reactive power transfer at the connection point except in accordance with applicable performance standards; and*

(iii) *the description of what is meant by stable voltage waveforms in the system strength requirements methodology is satisfied.* [13]

This means that Transgrid must ensure that forecasted IBR must remain stable at all times (during steady state or following a credible contingency) and must not destabilise the network or other IBR. Grid-following IBR need support to remain stable, either from adequate fault levels, or from grid-forming technologies that can directly stabilise voltage disturbances in real time.

Importantly, stable voltage waveforms are not assessed at the system strength nodes, but at the point of connection of future IBRs.

AEMO defines four criteria for stable voltage waveforms.[14] This RIT-T focuses on addressing Criterion 4 (voltage oscillations). Criteria 1 – 3 do not require any specific corrective actions as part of this RIT-T:

- Criterion 1 (voltage magnitude) is already addressed via traditional voltage control solutions (e.g. static var compensators, inductors, capacitors, transformer tap changers, reactive power support). Our analysis shows that once voltage oscillations (Criterion 4) is addressed, the forecast level of IBR does not cause any other voltage magnitude issues related to system strength;
- Criterion 2 (change in voltage phase angle) is satisfied if IBR are stable in steady state and after contingencies (i.e. NER S5.1.14(1) and (2) are met). These requirements are both achieved in the process of addressing Criterion 4; and
- Criterion 3 (voltage waveform distortion) is already addressed by Transgrid's business-as-usual setting, monitoring, and enforcement of harmonic emission limits.

Criterion 4 (voltage oscillations) is that *"any undamped steady-state root mean square (RMS) voltage oscillations anywhere in the power system should not exceed an acceptable planning threshold as agreed with AEMO."* Transgrid is currently applying a planning threshold for acceptable oscillations of up to 0.2 percent peak to peak RMS voltage, which is the lowest level reasonably achievable in a four-state wide-area network modelling environment, due to modelling artefacts. Where we observe forecast IBR causing voltage oscillations above this threshold, we will plan solutions (e.g. re-dispatch of existing synchronous machines, grid-forming BESS or synchronous condensers), that are able to dampen these oscillations to an acceptable level.

Transgrid uses a combination of RMS analysis (using AFL calculation in PSS®E) and electromagnetic transient (EMT) analysis (PSCAD™) to model stable voltage waveform requirements. This enables us to accurately model the benefits of grid-forming BESS, whose contribution to stable voltage waveform is unrelated to their fault current contribution, and hence not adequately represented in AFL calculations. Transgrid's EMT analysis uses models from real projects as templates for the forecast IBR, and models supplied by proponents and inverter manufacturers for grid-forming BESS solutions.

As part of the PACR preparation, Transgrid undertook (and published[15]) an assessment of stable voltage waveform remediation requirements from grid-forming BESS and synchronous condensers using the AFL proxy method versus detailed PSCAD™ studies. We concluded that the AFL method represented a useful long-term planning proxy for stable voltage waveform requirements, with PSCAD™ studies providing more accurate results.

2.2. Procurement timeframe as a result of this RIT-T

Transgrid is notionally seeking to procure long lead-time network solutions that are required in the first eight years of the modelled horizon following the completion of this RIT-T (i.e., out to 2032/33 inclusive). This is necessary in order to meet system strength requirements in NSW into the future, due to the long timeframes involved with the RIT-T process, and the procurement and commissioning of assets. This approach of proactively procuring long lead time network synchronous condensers, in addition to contracting with a portfolio of non-network solutions, will deliver the greatest net market benefits to consumers. The alternative would be prolonged gaps in system strength (as demonstrated in this PACR).

This approach is consistent with the PADR and aligns to the AER's guidance[16], which states *"It may be in the best long-term interests of consumers for a SSSP to procure long-term solutions for system strength, where these solutions are part of the credible option that maximises the present value of net economic benefit."*

While system strength solutions for the New England REZ have been identified as required prior to 2032/33, Transgrid will not commence procurement for them until EnergyCo has decided upon the approach and party responsible for system strength in the REZ. Based on lead-time assumptions used for this PACR, procurement does not need to occur until 2027/28 and as such, there is sufficient time to resolve this.

2.3. Key assumptions underpinning the identified need have changed since the PADR

While the overall characterisation of the identified need has not changed since the PADR, details regarding the amount and timing of system strength required, and the supporting assumptions, have been refined and updated to reflect latest information, as described below.

The minimum fault level requirements in the PACR remain unchanged since the PADR and are consistent with AEMO's 2024 System Strength Report.

13 AEMC, National Electricity Rules – Clause S5.1.14
14 AEMO, December 2022, System Strength Requirements Methodology
15 Aghanoori et. al., 2025, Comparison Between Synchronous Condensers and Grid Forming BESS in Providing System Strength Support to IBRs in Weak and Strong Power Systems Using EMT Simulation, CIGRE
16 AER, 2024, Efficient management of system strength framework – Guidance Note

2.3.1. Previously declared shortfalls in system strength

In the 2023 System Strength Report, AEMO declared projected system strength shortfalls at Newcastle and Sydney West from 1 July to 1 December 2025. Under NER Clause 11.143.15, as the SSSP for NSW, Transgrid was responsible for making system strength services available that, when enabled, would address this declared shortfall.

AEMO reassessed the projected system strength shortfalls in their latest 2024 System Strength Report, deferring shortfalls at Newcastle and Sydney West from 2025/26 to 2027/28. This deferral is linked with the delayed retirement date of Eraring Power station (to August 2027). This deferral has removed the obligation on Transgrid to make system strength services available from 1 July to 1 December 2025.

2.3.2. Requirements within the three year binding period

Transgrid's obligation to meet the standard under NER S5.1.14 defines the binding requirement and compliance year as the forecast requirements determined three years prior and, specifically, disregards any subsequent revisions, (Clause 5.20C.1I). The AER has provided further guidance for this requirement in December 2024, which states:[17]

"A SSSP's starting point for considering the steps it should take to meet the standard in clause S5.1.14(b) of the NER should be the level and type of inverter-based resources that AEMO forecasts (as part of determining the binding system strength requirement) will be connected in the compliance year. However, in considering what package of steps is reasonably required to meet the standard in the compliance year, one matter the SSSP could consider is the degree of certainty that the type and level of inverter-based resources reflected in the standard will materialise. This should take into account the best information available to the SSSP. In taking this matter into consideration, the SSSP should complete a holistic assessment using AEMO's forecast as a starting point."

As such, Transgrid has opted to adjust the IBR forecast within the three-year binding period (and in later years discussed in Section 2.3.3). We consider that the use of latest available information (such as connection applications) will lead to a more efficient outcome for consumers.

2.3.3. Efficient level requirements

While the overall characterisation of the identified efficient level requirements has not changed since the PADR and PADR Supplementary Report, the detail regarding the amount of system strength required has been refined. In the 2024 System Strength Report, AEMO updated its IBR forecast from the Final 2024 ISP to included updated committed and anticipated generation projects, updated status of network projects and the announced two-year delay to the retirement of the Eraring Power Station.

However, the revised delivery timetable announced by EnergyCo for the completion of the New England REZ Infrastructure Project was not incorporated. The revised timing represents a delay of more than three years to dates previously advised for Stage 1 (from September 2028 to July 2032) [18] and a delay to Stage 2 of three and a half years against the 2024 ISP Step Change timing (from July 2030 to January 2034) [19].

The revised delivery schedule for the New England REZ is expected to result in a material change to the timing and distribution of future IBR that was forecasted in the 2024 System Strength Report. Transgrid considers it is not prudent or efficient to use AEMO's 2024 System Strength Report IBR forecast as it does

[17] AER, December 2024, Efficient Management of System Strength Framework – Guidance note
[18] AEMO, December 2023, NEM Transmission Augmentation Information
[19] AEMO, June 2024, Network investments - Final 2024 ISP - Appendix 5

not take into consideration the latest available information and will lead to inefficient procurement of system strength solutions.

Transgrid has opted to plan to an IBR forecast which incorporates the revised timing of the New England REZ (Transgrid commissioned Baringa to develop this forecast). This IBR forecast was developed using the same modelling methodology that AEMO uses to develop the IBR forecast in its ISP and System Strength Reports.

A comparison of the IBR forecasts used for the PACR (developed by Baringa), and AEMO's 2024 and 2023 System Strength Report (used for the PADR) is shown in Figure 7 and Figure 8. The delay to the New England REZ transmission project results in a 5 GW reduction of IBR surrounding the Armidale node between 2028/29 and 2032/33 in the IBR forecast used in this PACR, compared to AEMO's 2024 System Strength Report. To replace IBR capacity displaced due to the delay in the New England REZ (necessary to meet demand as coal generators retire and to achieve legislated renewable energy and storage targets), the modelling identifies additional IBR capacity entering the Wellington and Darlington Point regions.

Once the New England REZ is delivered (from 2032/33), there is a significant growth in IBR forecast to enter the New England REZ and utilise the newly available transmission capacity. This drives the IBR forecasts surrounding the Armidale node to converge with AEMO's 2024 System Strength Report in 2037/38.

Figure 7. IBR forecast for Armidale, Buronga and Darlington Point nodes

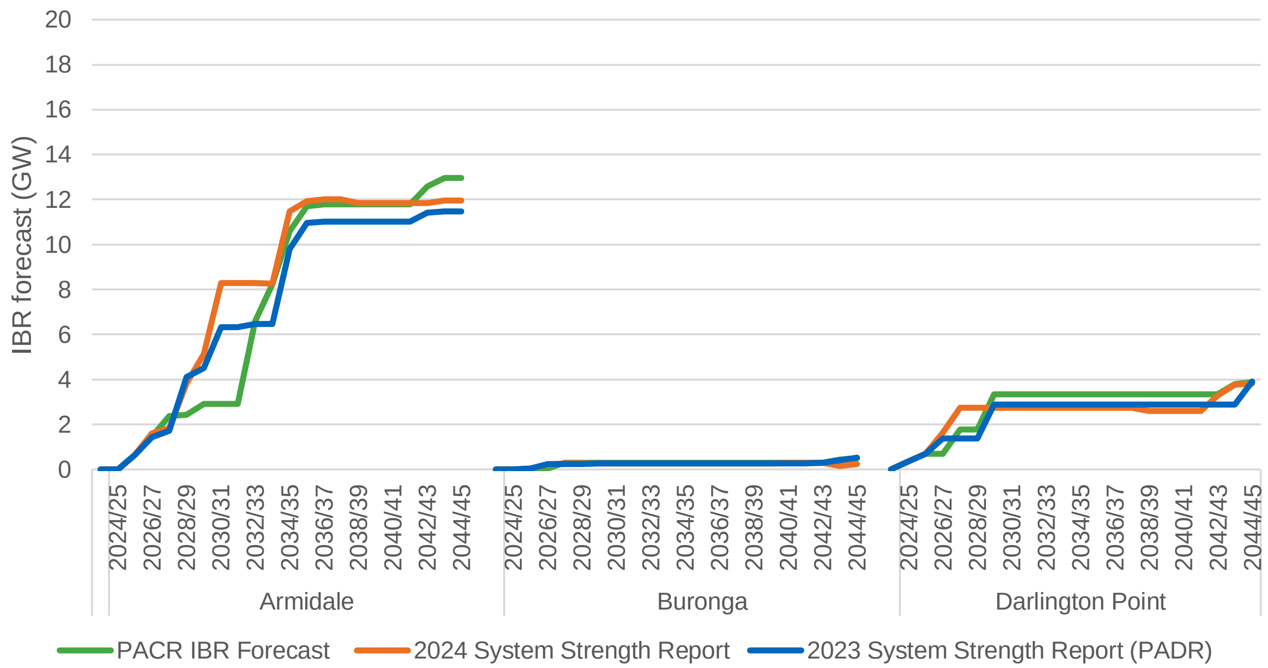
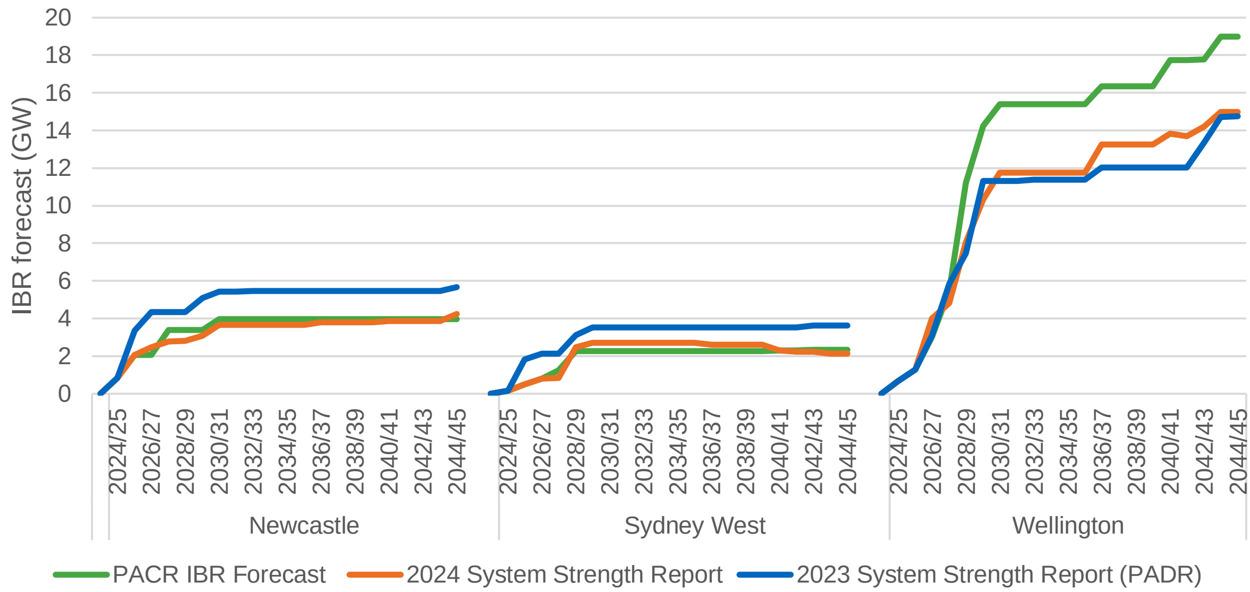


Figure 8. IBR forecast for Newcastle, Sydney West and Wellington nodes



This approach to adapt efficient level requirements based on latest available information follows guidance provided by AEMO in the 2024 System Strength Report, specifically:

"AEMO encourages Transgrid and EnergyCo to continue joint planning discussions, and to consider appropriate adjustments to the IBR projections based on the latest available information at time of RIT-T modelling, particularly where such assumptions can be consulted on through the RIT-T process itself."[20]

Transgrid has facilitated joint planning discussions with AEMO and EnergyCo throughout the adoption of this approach. AEMO is supportive of Transgrid's process and rationale in developing updated IBR forecasts and considers that the most efficient outcomes are delivered by applying latest available information at the time investment decisions are made. This approach is also consistent with the AER's guidance note[21], which clarified that SSSPs may use best information available to determine the appropriate provision of stable voltage waveform support.

With the exception of anticipated and committed IBRs connecting into the distribution network, and IBR modelled within the Hunter-Central Coast REZ, all other IBRs are modelled as connected to the transmission network, in line with AEMO's 2024 System Security Report (and 2024 ISP) forecasts. For future distribution-connected REZs, early Joint Planning and coordination will be required to determine the appropriate pathway for system strength remediation, given this need was not modelled in this PACR.

2.3.4. Self-remediation versus electing to pay the System Strength Charge

As part of the new system strength requirements, the 'do no harm' rules evolved into the System Strength Mitigation Requirement (SSMR), where new connecting parties may opt into a System Strength Charge

[20] AEMO, February 2025, 2024 System Strength Report
[21] AER, December 2024, Efficient Management of System Strength Framework – Guidance note

and their system strength remediation will be coordinated by the SSSP, rather than needing to self-remediate.

Transgrid's Connections team has assessed each project which submitted a Connection Application prior to 15 March 2023, who can choose to either progress under the previous 'do no harm' rules or opt into the new SSMR and elect to pay the System Strength Charge rather than having to self-remediate. Transgrid determined that all of these projects have elected to self-remediate under the previous rules and therefore do not require system strength provision by Transgrid. Transgrid assessed its connection pipeline at the time of market modelling (December 2024) and removed all projects from the IBR forecast which had elected to self-remediate.

There is limited availability of comprehensive data to indicate future self-remediation trends. For new and future IBR projects which fall under the new rule and haven't yet made an election, it is uncertain the proportion of future IBR that will opt in and elect to pay the System Strength Charge, versus self-remediating.

In lieu of sufficient data on the decision of wind and solar proponents, Transgrid has taken the conservative assumption that 100 percent of wind and solar projects will opt in and pay the System Strength Charge. Based on a larger (but still limited) set of battery projects moving through our Connection Application process, we have assumed that 60 percent of BESS projects will elect to self-remediate (by being grid-forming).

Transgrid's approach considers the asymmetric risk of under--procurement of system strength and the long lead-time of alternative system strength solutions. In the PADR, all BESS projects were assumed to pay the charge and were part of the efficient level need. As such, the approach for the PACR sees a reduction in the efficient level need, which is expected to avoid over-procurement of system strength solutions.

2.3.5. Remediation for Renewable Energy Zones

2.3.5.1. Central West Orana REZ Stage 1

In early 2023, EnergyCo informed Transgrid of its plan to centrally remediate system strength for stage 1 of the Central West Orana REZ (5.84 GW of IBR). Central remediation would be implemented by ACEREZ as the Network Operator, rather than by Transgrid, as NSW's SSSP. This was formalised in a letter from EnergyCo to Transgrid on 24 October 2023, and ACEREZ have now signed the commitment deed as the Network Operator for Central West Orana REZ.

ACEREZ and EnergyCo have advised us that seven 240 MVA-rated synchronous condensers are planned for the remediation of the first 5.84 GW of IBR within the Central West Orana REZ, with each synchronous condenser providing 834-955 MVA fault current at their 330kV point of connection. The assessment in this PACR assumes that each unit provides 834-955 MVA fault current.

Since the PADR, Transgrid has updated the delivery timing of the ACEREZ synchronous condensers used to remediate stage 1 of the Central West Orana REZ. The updated timing was provided by EnergyCo in April 2025.

At this stage, Transgrid does not have sufficient certainty on who will remediate IBR within Central West Orana REZ, beyond the first 5.84 GW. As such, this PACR assumes that Transgrid is responsible for remediating future IBRs in the REZ.

2.3.5.2. South West REZ

The South West REZ falls under Transgrid's obligations as the SSSP for NSW. This REZ is integrated within Transgrid's transmission network, with new IBR connections expected at or near Transgrid's Dinawan substation (being built as part of Project EnergyConnect). Transgrid's IBR forecast for the PACR has 2.6 GW of IBR capacity (all wind and solar, no batteries) expected to connect to the South West REZ, with the majority in 2029/30.

In May 2025, EnergyCo awarded 3.56 GW of Access Rights to IBR projects in the region, which includes approximately 3.6 GW of nameplate generating capacity and 700 MW of nameplate battery capacity. EnergyCo have advised Transgrid that the majority of projects are targeting connection in 2028/29, indicating a higher and earlier build-out of IBR than forecast for this RIT-T.

However, since the projects successful in the Access Rights process are still classified as proposed projects by AEMO, Transgrid has not adjusted the IBR forecast to include the full capacity of the Access Rights projects in the base case of this RIT-T. This is consistent with the RIT-T guidelines. However, using latest available information, Transgrid has updated the forecast IBR technology mix in the REZ based on the Access Rights tender (a higher proportion of wind generation).

In light of the difference between IBR capacity in the PACR forecast and the Access Rights tender, Transgrid has conducted a South West REZ sensitivity, where the IBR build-out is consistent with the nameplate capacities of projects that have been awarded Access Rights and their timing is consistent with advice from EnergyCo.

2.3.5.3. Hunter-Central Coast REZ

Occurring after the PADR, EnergyCo signed a commitment deed with Ausgrid in December 2024 for the delivery of the Hunter-Central Coast REZ Network Infrastructure Project.[22] EnergyCo states that the Hunter-Central Coast REZ will provide an additional 1 GW of network transfer capacity by 2028 [23] and the IBR forecast used within the PACR modelling suggests that 1.4 GW of IBR will connect by 2027/28. Most new IBR is projected to connect to a new sub-transmission switching station named Antiene.

While Ausgrid will deliver the REZ infrastructure, the responsibility for system strength remediation has been left to Transgrid, as the SSSP for NSW. Transgrid has consulted with Ausgrid in the development of the PACR, in response to Ausgrid's submission to the PADR Supplementary Report consultation. As a result, Transgrid has updated the location of IBR from Transgrid's network (as modelled in the PADR) to Ausgrid's network.

Due to limited system strength transfer between the transmission and distribution network, solutions for the Hunter-Central Coast REZ are expected to be located inside the REZ. As such, all system strength solutions considered for this REZ are non-network (Transgrid will contract for a non-network system security contact to procure and operate the solution as a part of the preferred portfolio option of this RIT-T).

2.3.5.4. New England REZ

While Transgrid currently has responsibility for system strength in the New England REZ (as SSSP for NSW), Transgrid understands that EnergyCo may adopt an approach outside of the NER framework to meet the REZ's system strength needs (e.g., central remediation by a third-party Network Operator).

[22] EnergyCo, Hunter-Central Coast Renewable Energy Zone
[23] EnergyCo, April 2025, Hunter-Central Coast Renewable Energy Zone - Summary of EnergyCo's network recommendation

In lieu of clarity from EnergyCo, modelling for the PACR has assumed that system strength remediation for IBRs within the New England REZ is the responsibility of Transgrid. However, noting the uncertainty, Transgrid has labelled any synchronous condenser required in the REZ as a 'REZ synchronous condenser', rather than a network (Transgrid) synchronous condenser.

Transgrid will not commit to the procurement of system strength solutions for New England REZ until EnergyCo's approach has been confirmed. Contingent upon EnergyCo's decision, system strength solutions identified for this REZ will remain or be excluded from the scope of Transgrid's procurement of the preferred portfolio option.

2.4. Inertia

In March 2024, the AEMC released its final determination for the 'improving security frameworks for the energy transition' rule change[24]. The final determination aligns inertia requirements with system strength, so that Transmission Network Service Providers (TNSP) can co-optimise inertia and system strength requirements together.

From 1 December 2024, AEMO set a ten-year forward requirement for the minimum system-wide inertia level, being the minimum amount of inertia required in the mainland states for continuous operation of the power system in a secure operating state. AEMO set a 'inertia sub-network allocation' for NSW at 9,600 MWs, for the period 2 December 2024 to 1 December 2034.

As part of the new rule, TNSPs must ensure inertia services are continuously available within three years of the requirements being published. Transgrid therefore needs to procure sufficient inertia from 2 December 2027 to meet these requirements.

Market modelling and power systems modelling for this system strength RIT-T was significantly progressed prior to AEMO's publication of NSW's inertia requirements. Therefore, co-optimisation of inertia and system strength requirements was not possible. However, the NSW power system will receive inertia support through the addition of flywheels on synchronous condensers, which are required to support stable voltage waveforms.

[24] AEMC, March 2024, Improving security frameworks for the energy transition

Inertia is essential for stable voltage waveform support

A core component of stable voltage waveform support is the ability to adequately damp voltage oscillations. Transgrid has concluded that inertia is integral to adequately damp voltage oscillations and therefore is integral to providing stable voltage waveform support.

Studies assessing the inertia required from synchronous condensers for stable voltage waveform support were performed – these studies identified an optimum inertia value of 1500 MWs required from each network (Transgrid) 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 2.5 percent increase to project costs (approximately, based on Transgrid's market sounding across multiple synchronous condenser manufacturers and internal Option Feasibility Studies).

The AER 'efficient management of system strength framework guidance note'[25] states that including a flywheel where a synchronous condenser has been found to be the preferred portfolio option (or part of a portfolio of solutions that together form the preferred portfolio option) is expected to be considered prudent and efficient expenditure, given the marginal cost of addressing inertia is typically relatively low. Transgrid's power system modelling suggests that high inertia synchronous condensers, necessary for stable voltage waveform support, will have a material flow on benefit in helping maintain sufficient inertia in NSW.

[25] AER, December 2024, Efficient Management of System Strength Framework – Guidance note

3. Stakeholder engagement throughout this RIT-T

Chapter summary

Stakeholder engagement has been integral to the development of inputs and modelling methodologies for this RIT-T. More than 60 non-network solutions from 30 proponents have been assessed and Joint Planning activities with AEMO, TNSPs, Distribution Network Service Providers (DNSP), EnergyCo, and other industry bodies have shaped the modelling which has taken place. Transgrid engaged directly with consumer and industry representatives through the Transgrid Advisory Council via system strength 'deep dive' workshops.

This PACR addresses feedback received during consultation periods for the PADR and PADR Supplementary Report. Two submissions were received for the PADR (from EnergyCo and Tesla) and one submission was received following the PADR Supplementary Report (from Ausgrid); all submissions have been published on our website.

Key changes from the PADR and PADR Supplementary Report

- Joint Planning activities with Ausgrid, enabling Transgrid to incorporate the latest network topology and expected IBR locations for the Hunter-Central Coast REZ;
- engagement with EnergyCo to identify system strength needs in the South West REZ, driven by the awarding of Access Rights for the REZ (studied via a sensitivity);
- additional Expressions of Interest from non-network solutions enabled twenty-eight new projects to be included; and
- commercial Expressions of Interest from proponents of non-network solutions, informed by three industry briefings.

Industry and proponent engagement is an important part of the RIT-T process, and we thank all parties for their valuable input to the consultation process. The analysis presented in this PACR has been strongly informed by consultation over the course of the RIT-T, which has helped shape the analysis.

3.1. Industry engagement

Transgrid engaged stakeholders consistent with its requirements outlined in NER Clause 5.15.4. A range of stakeholder information sessions and meetings were held to support the stakeholder engagement process, with key engagement milestones and a summary of formal responses received outlined in Table 5.

Table 5. Summary of the key milestones for consultation and responses received

Milestone for consultation	Method of engagement	Stakeholder responses
PSCR, December 2022	Submissions were requested over a 12-week consultation period, concluding on 30 March 2023.	Five submissions including one confidential response. Non-confidential submissions from Energy Australia, Origin Energy, Smart Wires and Tesla were published on our website.
EOI for non-network solutions, December 2022	Email used for Expressions of Interest. Also published via website. Returnable schedule used to provide technical	61 project EOIs were received.

Sensitive

Milestone for consultation	Method of engagement	Stakeholder responses
	characteristics of the proposed solution.	
PADR, June 2024 Additional documents were published via Transgrid's website providing information on modelling, technical performance of synchronous machines and grid-forming BESS and guidance for non-network proponents.	Submissions were requested over a six-week consultation period, concluding on 2 August 2024.	Two submissions received. Submissions from EnergyCo and Tesla were published on our website.
Non-network solution EOI re-engagement and re-opening for new solutions, June 2024	Proponents were re-engaged via email.	28 new projects were received.
Industry engagement of technical requirements for grid-forming BESS, June 2024	Two public industry briefings were held, plus an additional to the Clean Energy Council, providing guidance for proponents of non-network solutions.	No formal submissions were raised.
Commercial EOI for non-network solutions, August 2024	Submissions were requested over a five-week period, concluding on 26 September 2024.	All proponents of non-network solutions were requested to return a commercial component to the EOI containing indicative pricing information.
Supplementary Report to the PADR, October 2024	Submissions were requested over a 4-week consultation period, concluding on 15 November 2025.	One submission received from Ausgrid, which has been published on our website.

As noted in the table above, three submissions have been received since the PADR. Across these submissions, four broad areas were raised for consideration, including:

- consideration of recent REZ developments when planning for the efficient level of system strength;
- the treatment of the Hunter-Central Coast REZ;
- the timing and scope of non-network options, in particular grid-forming batteries; and
- the broader RIT-T framework.

We have taken all feedback raised in submissions and stakeholder feedback sessions into account in undertaking our PACR analysis. The key changes that have been incorporated into this PACR in response to the PADR consultation are:

- updated network topology and treatment of IBR in the Hunter-Central Coast REZ;
- consideration of higher IBR build-out in the South West REZ (via a sensitivity), resulting from the award of Access Rights in May 2025; and
- extensive network studies to assess the benefit of grid-forming BESS for stable voltage waveform support.

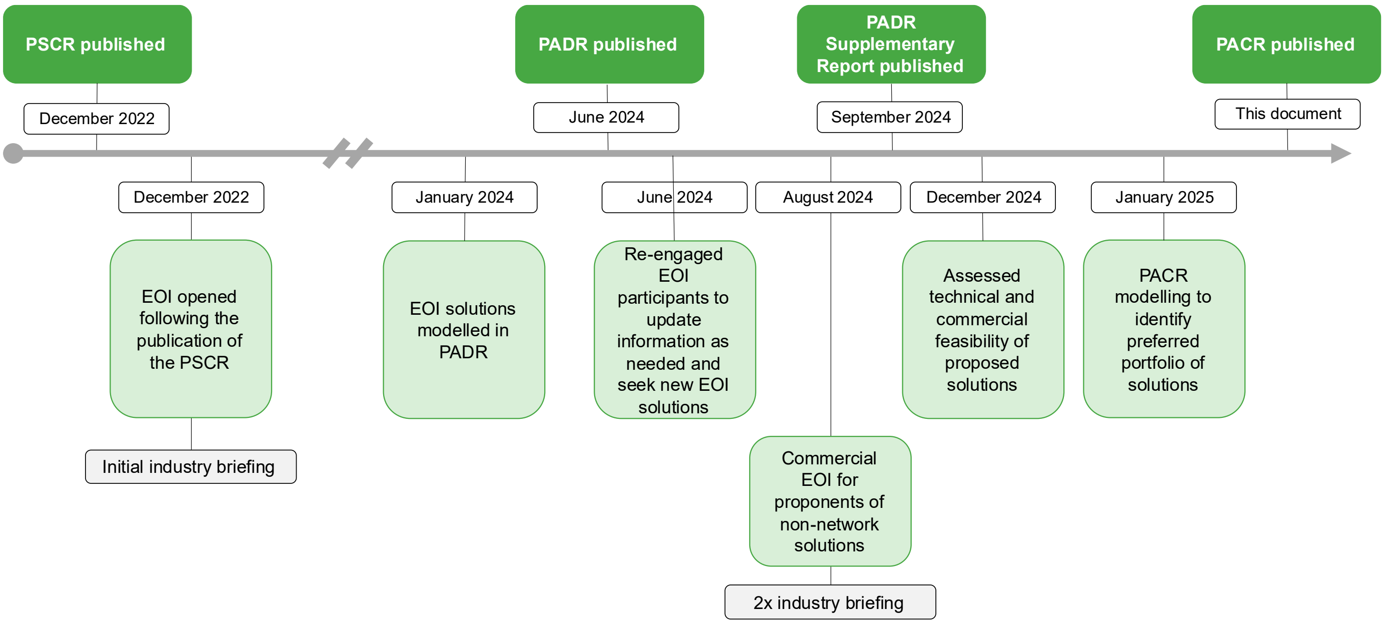
A full summary of all matters raised as part of consultation on the PADR is provided and responded to in Appendix D.

3.2. Non-network proponent engagement

In addition to engaging with stakeholders throughout consultation periods, Transgrid has requested EOIs from non-network proponents throughout the RIT-T process. This process was initiated by Transgrid following publication of the PSCR. Following the PADR, Transgrid re-engaged EOI proponents given the time passed since the original submissions to firm up technical and cost information for their projects and confirm their technical and commercial feasibility. New proponents also had the opportunity to submit EOIs for consideration in the PACR. Proponents were asked to provide a commercial EOI for their non-network solutions. All responses were assessed and considered for inclusion in the PACR.

Overall, more than 60 non-network solutions have been assessed from 30 different proponents, with further details in Section 4. A timeline of the EOI process is shown in Figure 9.

Figure 9. Expressions of Interest process followed for non-network solutions



Following conclusion of the RIT-T process (and in parallel where appropriate), Transgrid will commence procurement processes for non-network solutions. Additional feasibility assessments, in particular for grid -forming batteries, will be required at this point to validate the technical performance of each individual solution. Further explanation of Transgrid's assessment of grid-forming batteries for system strength provision is provided in Section 4.4.1.

3.3. Joint Planning

Throughout the RIT-T, Transgrid undertook Joint Planning with industry bodies including AEMO, TNSPs, Ausgrid and EnergyCo. Joint Planning has facilitated a more efficient outcome which is tailored to the latest and best available information. Areas of Joint Planning included:

- system strength requirements, power system and market modelling methodologies and interstate system strength transfers, with AEMO and SSSPs via monthly Working Group meetings and ad hoc engagements;
- more specific interstate system strength transfers, in particular with AEMO Victorian Planning and Powerlink;
- system strength provision and interactions within and between REZs and the transmission backbone with EnergyCo, in particular for Central West Orana REZ; and
- Hunter-Central Coast REZ Network Infrastructure with Ausgrid.

4. Individual solutions assessed

Chapter summary

Transgrid has assessed more than 100 individual system strength solutions as part of this RIT-T, of which over 60 were non-network. Non-network solutions include synchronous generation technologies such as hydro, gas, coal, biomass and compressed air storage, as well as grid-forming batteries and synchronous condensers.

Transgrid has also assessed 46 additional individual solutions including grid-forming BESS and synchronous condensers in locations identified as optimal for system strength provision on the Transgrid network.

Key changes from the PADR and PADR Supplementary Report

- technical and commercial feasibility assessments of network and non-network solutions was conducted. All solutions were assessed to be feasible;
- assessment of grid-forming BESS projects in PSCAD™ to refine assumed capacity to support stable voltage waveforms;
- twenty-eight new non-network solutions received through updated Expressions of Interest;
- inclusion of a new gas supply constraint on gas-powered generators supplied by the Sydney-Newcastle pipeline, based on advice from GHD;
- Kemps Creek replaced Sydney West as the preferred location for a network synchronous condenser to contribute to the Sydney West system strength node due to site constraints; and
- revised the earliest credible timing of network (Transgrid) synchronous condensers from July 2028 to a range between March 2029 (earliest credible, yet optimistic timing) and February 2030 (more likely credible timing).

4.1. Transgrid has engaged proponents on non-network solutions

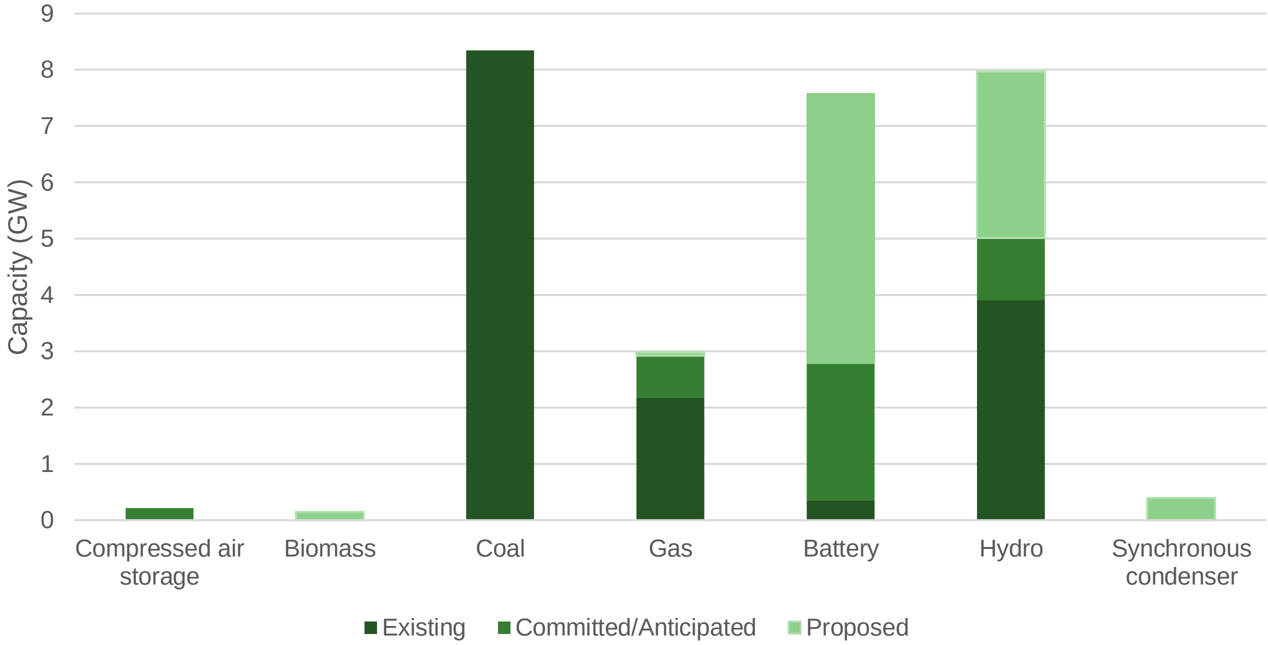
The EOI process resulted in non-network solution submissions from 30 parties, covering over 60 individual potential solutions, including:

- more than 14 GW of existing or modifications of existing synchronous generators;
- over 3 GW of other new generation and energy storage projects, including pumped hydro, gas and compressed air storage;
- a pipeline of more than 7.5 GW of batteries (inclusive of grid-forming and grid-following); and
- several non-network synchronous condensers.

Since the PADR, dozens of new responses were received for new non-network solutions and dozens of proponents withdrew their proposals. The confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West, which was considered as part of portfolio option 3 in the PADR, was also withdrawn and so this solution is not considered further in the PACR.

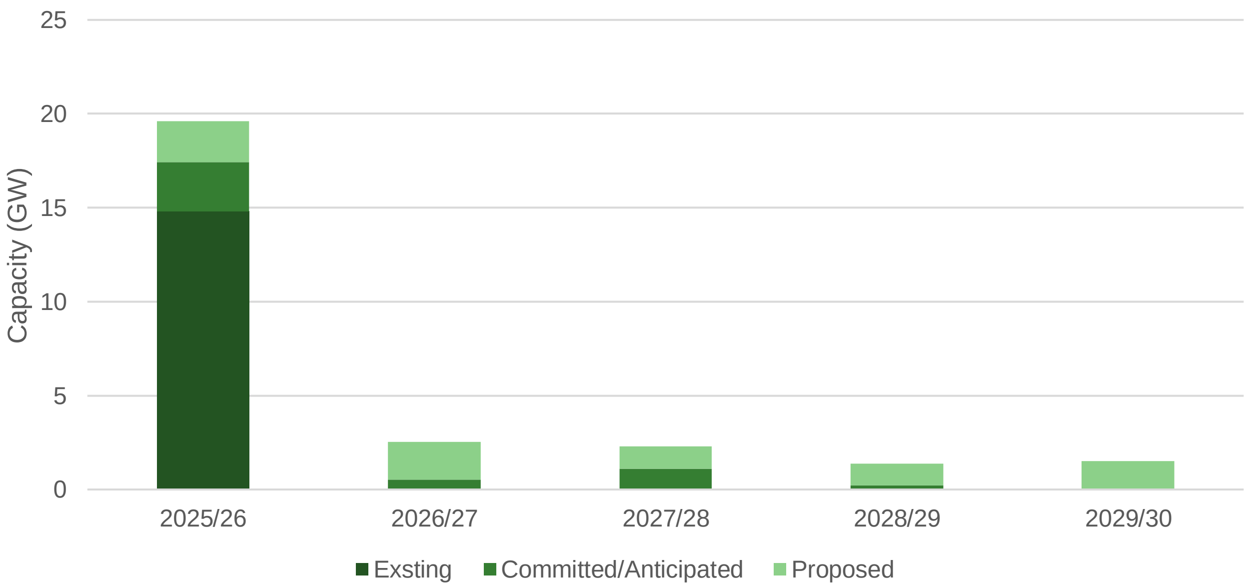
The breakdown of non-network solutions by technology and status is shown in Figure 10.

Figure 10. Breakdown of non-network solutions by technology and status[26]



Most non-network solutions are available to provide system strength services from the beginning of the period of analysis, as they are already existing synchronous generators, as shown in Figure 11.

Figure 11. Earliest available data for system strength services from non-network solutions



Proposed non-network solutions have been assessed in the PACR modelling if deemed technically and commercially feasible in line with the RIT-T guidelines[27].

[26] Synchronous condensers do not produce power, the value shows the rated capacity (MVA) of proposed synchronous condensers.

[27] AER, 2024, Regulatory investment test for transmission application guidelines

4.2. Network solutions proposed

Transgrid also included potential network solutions to meet the system strength need, including synchronous condensers and grid-forming BESS.

Each synchronous condenser is modelled to provide 1,050 MVA fault level contribution at the point of connection to the transmission network (locations are provided in Section 5.1) and 1,500 MWs of inertia. The fault level contribution decreased from 1,150 MVA used in the PADR, based on discussions with suppliers. Although 1,050 MVA has been modelled for this PACR, during the procurement process the size may be adjusted based on the market response, for example to unlock lower costs or faster delivery. It is expected that the combined fault level provision of the procured portfolio of synchronous condensers will stay consistent with PACR outcomes, irrespective of the size of each synchronous condenser procured. For example, Transgrid may select a supplier providing two 525 MVA fault level synchronous condensers as an equivalent solution to a single 1,050 MVA fault level solution.

Transgrid has also proposed grid-forming BESS solutions, labelled 'targeted' grid-forming BESS. 'Targeted' grid-forming BESS refer to grid-forming BESS that do not currently have a proponent but have been included in this RIT-T by Transgrid as an alternative solution to synchronous condensers. These are modelled to be located at or near a transmission substation. These proposed solutions are sized through the PLEXOS optimisation process to 'perfectly' match the efficient level need. If 'targeted' grid-forming BESS are included in the preferred portfolio, they may be delivered as a network or non-network solution.

Transgrid will update its analysis to confirm the specific optimal location for these 'targeted' grid-forming BESS prior to their procurement; in general, these grid-forming BESS should be connected as close as possible (electrically) to large groups of IBR requiring remediation.

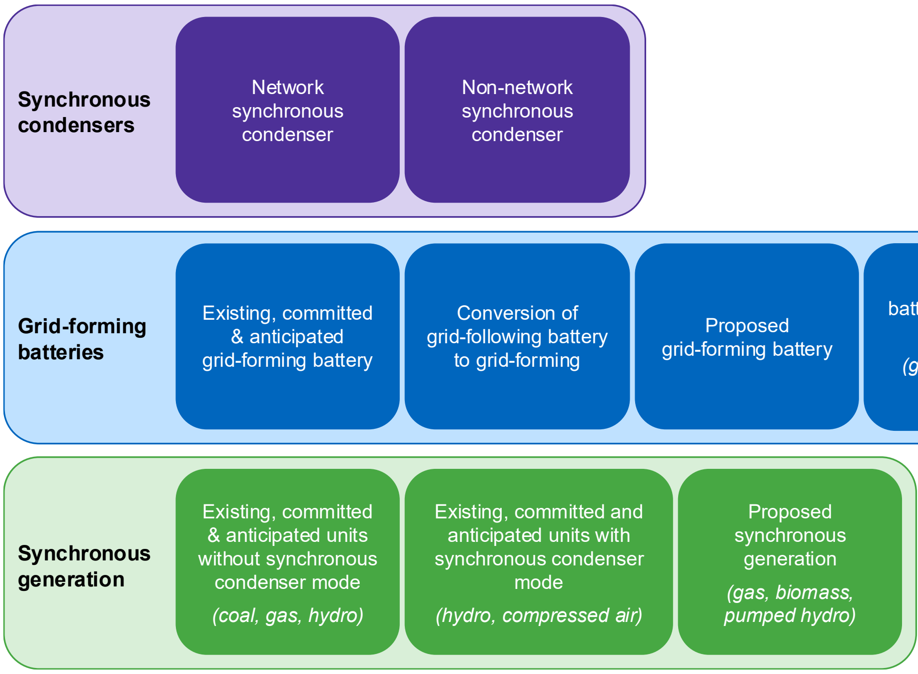
Grid-forming Static Synchronous Compensators (STATCOMs) coupled with a supercapacitor were considered as a solution in the PADR. The PADR modelling showed that STATCOMs were not selected as part of the optimal portfolio. As such, Transgrid did not consider STATCOMs as potential solution for the PACR assessment.

4.3. Summary of all individual solutions assessed in the PACR

This section outlines how individual solutions proposed in submissions to the EOI, and network solutions, have been considered and included as part of the PACR assessment. The range of solutions are presented in Figure 12.

The range includes BESS that are forecasted within Baringa's generation and storage outlook, in line with the ISP Step Change approach (termed 'ISP-modelled' BESS in this PACR), which are available to for Transgrid to contract with for system strength services.

Figure 12. Range of solutions considered within this RIT-T



Details on the description and treatment of each individual solution is tabulated below.

Table 6. Description and treatment of each individual solution within this RIT-T

Solution	Description
Synchronous condensers	Synchronous condensers provide system security services only; they do not produce electricity.
Network synchronous condenser	• Represented as a load in market modelling, with the size of load set by losses. • Each synchronous condenser solution is assumed to provide 1,050 MVA fault level contribution at its point of connection to the transmission network and 1,500 MWs of inertia.
EOI-proposed non-network synchronous condenser	• Represented as a load in market modelling, with the size of load set by losses. • Size and cost of non-network synchronous condensers is taken from proponent information.
Grid-forming BESS	A grid-forming BESS may contribute to the efficient level by having its inverters online (no requirement to charge/discharge). Grid-forming BESS can only contribute to meeting the minimum level of system strength from 2032/33; further details in Section E.3.
Committed and anticipated BESS	Assumed as part of the base case and all portfolio option cases: • Grid-following BESS may have been proposed through the EOI to upgrade to grid-forming BESS. Only the upgrade cost is considered for PACR modelling.
Proposed grid-following or grid-forming BESS	• Specific projects put forward by proponents in response to our system strength EOI. • Not considered committed or anticipated under the RIT-T at this stage, therefore full capital cost is modelled.
ISP 'modelled' grid-following BESS, converted to grid-forming	• Future BESS which are part of the generation build path within Baringa's ISP-equivalent Step Change scenario are assumed to be in the base case and all option cases.

	• All 'ISP-modelled' BESS are assumed to be grid-following, which have the option to upgrade to grid-forming. Only the cost of the upgrade is considered as a capital cost. • Transgrid has assumed that developers of the 'ISP-modelled' batteries in AEMO's ISP forecast would, acting reasonably, be willing to upgrade their batteries from grid-following to grid-forming, if Transgrid offered a system security contract that supported the business case of doing so.[28]
'Targeted' grid-forming BESS	• New grid-forming BESS which are sized specifically to the system strength need rather than tied to a specific project. Their size and location are optimised through PLEXOS; the locations considered are outlined in Section 5.2. • Solutions may be network or non-network solutions. • Not considered in the base case so entire capital cost is considered for PACR modelling.
Synchronous generation	Synchronous generation contributes to the minimum and efficient levels of system strength. This is achieved whenever the unit is operating, either as a byproduct of normal operation (with no additional cost) or via 're-dispatch', which could also include operation in synchronous condenser mode (if applicable).
Existing/committed/anticipated synchronous generation without synchronous condenser mode	• This category includes coal and gas generators, as well as some hydro units and compressed air storage. • May have EOI to upgrade to include synchronous condenser mode. Cost of upgrade is the only capital cost considered in PACR modelling.
Existing synchronous generation with synchronous condenser mode	• Existing hydro plants that already can switch between operation as part of normal market dispatch (and generate electricity) or operation in synchronous condenser mode (providing system security without generating electricity). • Projects have no capital cost.
Proposed synchronous generation	• Capable of providing system strength through normal operation or in synchronous condenser mode (if able). • Not considered committed or anticipated and so full capital cost is assessed for PACR modelling.

4.4. Technical feasibility assessment

For the PADR, Transgrid assumed that all non-network solutions were technically feasible to determine whether the solutions are likely to form part of the overall preferred portfolio option.[29] Following the PADR Supplementary Report, Transgrid assessed the technical and commercial feasibility of all eligible solutions.

Transgrid hosted industry briefings in June and August 2024 to provide guidance for non-network proponents. Transgrid consulted upon and published detailed technical performance and power system

[28] 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.

[29] The one exception to this is for the confidential proposal to provide synchronous condenser services in the vicinity of Newcastle and Sydney West where it was only assumed to be technically feasible for one portfolio option ('portfolio option 3'). This proposal has since been withdrawn and is not considered as an option in the PACR.

modelling requirements for both synchronous machines[30] and grid-forming inverters[31]. Through this process, Transgrid extensively engaged with proponents and provided information to ensure proponents were equipped to provide accurate submissions.

All solutions were assessed to be commercially feasible for the purposes of market modelling, noting a project is considered commercially feasible if:

"An option is commercially feasible under NER clause 5.15.2(a)(2) if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options."[32]

For the PACR, technical feasibility was assessed for all solutions and technologies. The method of assessment and key changes since the PADR are summarised by technology in Table 7. For further details of Transgrid's technical feasibility assessment, see Appendix E.

Table 7. Technical feasibility assessment and findings by technology

Technology	Method of assessment	Key changes since the PADR
Network synchronous condenser	Option Feasibility Studies were conducted by Transgrid for specific sites. Suppliers of synchronous condensers were engaged.	• American Association of Cost Engineering (AACE) Class 4 cost estimate equivalent obtained. • Kemps Creek considered most appropriate location for synchronous condensers to support the Sydney West node (instead of Sydney West itself) due to site feasibility and cost. • New locations investigated for inclusion in the PACR. • Revised the earliest credible timing of network synchronous condensers from July 2028 to a range between March 2029 (earliest credible, yet optimistic timing) and February 2030 (more likely credible timing). • Each subsequent synchronous condenser is staggered in 1.5-month intervals.
Non-network synchronous condenser	Solutions were assessed by Transgrid using information from suppliers and in-house Option Feasibility Studies.	• Project schedule adjusted to reflect timing of RIT-T regulatory and procurement process.
Grid-forming BESS	PSCAD™ assessment in Single Machine Infinite Bus and four-state wide-area models.	• Grid-forming BESS modelled to contribute to the nearest node region only for the efficient level. • Boost factors refined by grid-forming inverter supplier.
Hydro	Independent assessment by GHD of additional re-dispatch hours and synchronous condenser mode modifications.	• Variable operation and maintenance costs were assessed to be equivalent whether hydro is operating in generation, pump or synchronous condenser mode.
Gas	Independent assessment by GHD of additional re-dispatch hours.	• Daily gas supply constraint applied to gas generators supplied by the Sydney-Newcastle gas pipeline.
Coal	Exclusively existing solutions, no additional assessment was required.	N/A

[30] Transgrid, 17 June 2024, Technical performance and power system modelling requirements for a synchronous system security service

[31] Transgrid, 17 June 2024, Transgrid's technical performance and power system modelling requirements for stable voltage waveform support services from grid-forming BESS

[32] AER, 2024, RIT-T application guideline

4.4.1. Grid-forming battery contribution to system strength

Grid-forming batteries can co-optimise 'efficient' level system strength support with other market benefits. However, grid-forming inverter technology has not yet been deployed and tested at scale to support the minimum level of system strength. Comprehensive power system and protection studies need to be undertaken to confirm the effectiveness of grid-forming battery technology to provide minimum fault level support (including for the safe operation of protection devices).

This is consistent with advice from AEMO. Specifically, in December 2024, AEMO's 2024 Transition Plan for System Security[33] states that the efficient level of system strength *"may be met by a variety of existing or new technologies, including grid-forming inverters"*. However, *"minimum levels of system strength must be provided by protection quality fault current, which grid-forming inverters have not yet demonstrated capability to provide"*. This is also consistent with AEMO's position as published in the May 2024 update to the 2023 Electricity Statement of Opportunities (ESOO) [34].

Transgrid engaged Aurecon to undertake an independent assessment of the maturity of grid-forming batteries for system strength support. This assessment concluded there is insufficient evidence (either at-scale deployments or modelled) to rely on grid-forming BESS to support minimum fault level needs until 2032/33.

Further details of the technical feasibility of grid-forming batteries see Appendix E.3.

This RIT-T helps support the pathway to proving the credibility of grid-forming batteries to support the minimum level of system strength

Transgrid recognises the significant opportunity grid-forming BESS provide for supporting the efficient level of system strength. This RIT-T has included 5 GW of grid-forming BESS by 2032/33 and 8.1 GW by 2044/45 in all portfolio options. This is estimated to require $2.6 billion in capital costs and $0.5 billion in operating costs in addition to the investment forecast by AEMO under the Step Change scenario. This fleet of grid-forming BESS is intended for the efficient level across the assessment period and for the minimum level from 2032/33.

In preparation for this PACR, Transgrid has engaged proponents of battery projects and grid-forming inverter original equipment manufacturers to perform network studies to assess the contribution of grid-forming batteries to maintain a stable voltage waveform. Over time, these models will be used to facilitate network studies to build confidence and identify areas of improvement in grid-forming batteries to support the minimum level, specifically the fault current response of grid-forming batteries to contingency events and its interaction with protection equipment in the transmission and distribution network (and/or identify where changes to protection equipment may be required).

Transgrid will monitor the fault current responses and operation of grid-forming batteries in the field, assessing their behaviour against the challenges indicated in the Aurecon report. Transgrid is already engaged in dedicated technical forums and working groups with AEMO and other key stakeholders to explore the role of grid-forming technology for the minimum level of system strength.

[33] AEMO, December 2024, Transition Plan for System Security
[34] AEMO, May 2024, Update to the 2023 Electricity Statement of Opportunities

5. Estimating individual solution costs

Chapter Summary

This section outlines how individual system strength solutions (both network and non-network) have been costed for the purposes of the PACR 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 Original Equipment Manufacturers and adoption of costs used by AEMO 2023 Inputs, Assumptions and Scenarios Report (IASR).

Following the PADR, Transgrid engaged GHD to undertake an independent assessment of costs provided by non-network proponents of existing and committed hydro (including proposed upgrades to enable synchronous condenser capability), and gas units, where AEMO's IASR values were not used.

Key changes from the PADR and PADR Supplementary Report

- revised site locations and cost estimates for network synchronous condensers based on Transgrid Option Feasibility Studies and supplier engagement;
- revision of fixed and variable operating and maintenance costs for both gas and hydro plants based on independent assessment by GHD; and
- proponents of non-network solutions from the EOI were re-engaged to confirm costs and details of proposed solutions.

In preparing this PACR, Transgrid has used the best available information on the timing and costs of non-network and network solutions. Transgrid has continued to use the 2023 IASR to underpin modelling for this RIT-T. Although, the draft 2025 IASR was recently published, it had not finished consultation and Transgrid had already commenced market modelling. Transgrid's investigation indicates that using the draft 2025 IASR would not materially affect the results of the PACR.

5.1. Costs of network and REZ synchronous condensers

Cost estimates for network and REZ synchronous condensers are based on Transgrid Option Feasibility Studies (OFS), which include the components and associated substation works for each location. These cost estimates have been derived from Original Equipment Manufacturer quotes (for synchronous condensers) and Transgrid's internal estimating tool for the civil and balance of plant costs.

Where an OFS was not completed, a desktop study was completed to identify a suitable cost estimate based on the costs of a comparable site with an OFS completed. The use of desktop studies reflects the rapidly evolving need for system strength (and synchronous condensers) between the PADR and the PACR, as key assumptions and inputs changed.

Since the PADR, the estimated costs for synchronous condensers have increased by approximately 90% following further supplier engagement and additional studies of the sites. The increase is a response to rising global demand for synchronous condensers in a supply-constrained market (and associated civil and balance of plant works).

In total, we have modelled and costed synchronous condensers for 15 separate locations as described in Table 8.

Table 8. Description of the locations of proposed network synchronous condensers

Nearest system strength node	Synchronous condenser location	Basis for cost estimate
Armidale	Armidale 330 kV	Option Feasibility Study
	Tamworth 330 kV	Option Feasibility Study
	New England REZ	Estimate for Armidale used
Buronga	Broken Hill 220 kV	Average of all synchronous condenser costs and linearly decreased on a per MVA basis for smaller size and increased by a factor of 25% to reflect reduced cost efficiency
Darlington Point	Darlington Point 330 kV	Option Feasibility Study
	Wagga Wagga 330 kV	Estimate for Wellington used
	Yass 330 kV	Option Feasibility Study
	Dinawan 330 kV	Option Feasibility Study
Newcastle	Newcastle 330 kV	Option Feasibility Study
	Liddell 330 kV	Option Feasibility Study
	Eraring 330 kV	Assumed the same cost as Liddell 330 kV. Desktop study completed and Option Feasibility Study is being prepared
	Muswellbrook 330 kV	Average of costs for Sydney West and Wellington
	Synchronous condenser solution in Hunter-Central Coast REZ, Antiene 132 kV	Average of all synchronous condenser costs on a per MVA basis for smaller size and increased by a factor of 25% to reflect reduced cost efficiency
Sydney West	Kemps Creek 330 kV	Option Feasibility Study
Wellington	Wellington 330 kV	Option Feasibility Study

The synchronous condenser locations removed since the PADR are shown in Table 9.

Table 9. Locations removed from the system strength PACR assessment

Location	Justification
Glen Innes 132 kV	PADR modelling did not select these locations due to each location's lower effectiveness to contribute towards system strength requirements. The technical feasibility of the remaining locations confirmed the capacity to accommodate the number of synchronous condensers identified in the PADR. Therefore, these locations were removed as an option from the PACR to improve the tractability of market modelling (model solve time).
Darlington Point 132 kV	
Vales Point 330 kV	
Cooma 132 kV	
Wollar 500 kV	
Sydney West 330 kV	Options Feasibility Study revealed site constraints which would materially increase the cost and risk to delivery timing of installing a synchronous condenser. Kemps Creek was selected as the preferred location for a synchronous condenser contributing to the Sydney West system strength node.

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

- the scope of works required;

- general site arrangement and access issues;
- property considerations;
- civil works;
- biodiversity offsets;
- building works;
- plant and equipment (major and minor);
- electrical works;
- secondary systems; and
- interaction with related projects (such as other transmission upgrade projects).

The costs used for these estimates are based on information provided by synchronous condensers suppliers in Q3 2024, as well as balance of plant and construction costs, derived from Transgrid's cost estimating database up to early-2025. Transgrid recognises the supply chain for synchronous condensers is tight and there is significant global demand for this equipment, as such, these costs represent a point in time estimate. Transgrid will continue to engage the market before and during procurement to confirm binding prices (which may be different to what was estimated for this PACR). Sensitivity analysis in Section 9.1.2 identifies that a 30% increase in synchronous condenser costs does not change the amount or timing of Transgrid synchronous condensers required before 2030/31. The average cost assumed in the PACR of a selected network synchronous condenser is $160 million including balance of plant and commissioning.

Transgrid's 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.

Transgrid reviews its cost estimating database 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. As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

While we have not explicitly applied the AACE cost estimate classification system,[35] we estimate that actual costs will be within -20% to +30% of the base capital cost estimate, consistent with a Class 4 estimate, as defined in the AACE classification system. No contingency allowance has been included in the network cost estimates.

Significant land acquisition costs are not expected for the portfolio of network synchronous condensers, since they have been assessed to be co-located on existing Transgrid land in most cases.

We have assumed an annual operating and maintenance cost for synchronous condensers of 0.6 percent of the upfront capital expenditure. This is consistent with the AER's final decision on ElectraNet's system strength contingent project,[36] as well as discussions with suppliers of synchronous condensers.

[35] 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.

[36] AER, August 2019, ElectraNet Contingent Project Main Grid System Strength

5.2. Costs of 'targeted' grid-forming BESS (either non-network or network solutions)

'Targeted' grid-forming BESS do not currently have a proponent but have been included in this RIT-T by Transgrid as an alternative new-build solution to synchronous condensers. These solutions, if selected within the PACR modelling, may be delivered as either non-network or network solutions. These 'targeted' grid-forming BESS are assumed to be in optimal locations from a system strength perspective and are optimally sized to meet the system strength requirements (while also providing additional energy market benefits).

As these solutions have proposed status, rather than committed or anticipated, they incur the full capital cost in our modelling, not just the incremental cost to switch from grid-following to grid-forming as applied for existing, committed, anticipated projects or ISP-modelled BESS as outlined in Section 4.3. All costs and other assumptions regarding the technical operation of 'targeted' grid-following BESS have been sourced from the 2023 IASR assumptions. The modelling considers the full impact of 'targeted' BESS (and all others) on wholesale market outcomes, including changes in other plants' fuel costs, generator and storage costs and greenhouse gas costs.

The table below summarises the locations of targeted grid-forming BESS considered in the PACR assessment. The locations have not changed since the PADR and have been selected in areas which correspond with high levels of forecast IBR uptake.

Table 10. Locations of grid-forming BESS modelled in the PACR assessment

Node	Locations
Armidale	Armidale 330 kV Within New England REZ (from 2031/32)
Buronga	Buronga 220 kV Broken Hill 220 kV
Darlington Point	Darlington Point 330 kV Darlington Point 132 kV Yass 330 kV Bannaby 330 kV
Newcastle	Newcastle 330 kV Bayswater 330 kV Liddell 330 kV Muswellbrook 330 kV
Sydney West	Sydney West 330 kV Kemps Creek 330 kV
Wellington	Wellington 330 kV Wollar 330 kV Wollar 500 kV

5.3. Non-network costs

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

5.3.1. Treatment of anticipated and committed non-network projects

In preparing this PACR, we have engaged with non-network proponents on the status of their projects. Specifically, how their solutions are progressing against the criteria used to assess whether projects are considered 'anticipated' or 'committed' under the RIT-T.

The RIT-T defines a 'committed' project as one that meets the following criteria, and an 'anticipated' project as one that is in the process of meeting at least three of the criteria:

- 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.

All projects that we have considered as 'anticipated' or 'committed' in the PACR assessment have the same status in AEMO's October 2024 NEM generation information workbook. All proponents who suggested their projects should be considered 'anticipated' but were not classified as anticipated in the October 2024 version of AEMO's generation information workbook, were assessed against the RIT-T criteria based on the information provided by proponents and were determined by Transgrid to be 'proposed' for the PACR assessment.

'Anticipated' or 'committed' projects have been included in the base case and all portfolio 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 applied project cost estimates to the extent they differ to what has been assumed in the base case.

5.3.2. Non-network grid-forming BESS

For proposed BESS projects (i.e., those that are not included in the base case), their assumed costs can significantly influence the RIT-T outcome. In order to ensure fairness and consistency of cost data (noting that proponents provide costs at varying stages of project maturity), 2023 IASR cost assumptions have been applied to all proposed BESS projects, along with an allowance for conversion to grid-forming capability where appropriate (as outlined in Section 5.3.2.2 below).

5.3.2.1. Anticipated and committed BESS projects

All EOI 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 portfolio 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 any costs relating to grid-forming capability are only included in the portfolio option cases. 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. This was assumed to take 12 months (informed by Transgrid's experience with the Wallgrove Grid Battery) and cost one percent of the upfront capital cost (informed by discussions with various parties in the industry)[37]. This one percent assumption seeks to reflect the costs of the NER 5.3.9 application process and assumes no significant hardware upgrades are needed. Projects which are existing with grid-forming capability or anticipated/committed projects which have a contractual commitment to connect in grid-forming mode were assumed to have no additional costs.

5.3.2.2. Proposed and ISP-modelled BESS projects

Proposed and ISP-modelled grid-forming BESS have been costed using the 2023 IASR assumptions.

For proposed grid-forming BESS, the entire capital cost is considered in PACR modelling. As the IASR does not delineate between the cost of grid-following and grid-forming BESS, it is assumed a proposed BESS will incur a five percent incremental cost higher than the IASR cost to account for higher costs of grid-forming inverters and higher modelling costs during the connection process. This value was informed through engagement with industry.

AEMO's 2024 ISP modelling does not explicitly make a distinction between grid-following and grid-forming inverters. For the purposes of PACR modelling, all ISP-modelled BESS are treated as grid-following and are part of the base case. As they are part of the base case, the RIT-T only modelled the increase in cost from selecting grid-forming inverters (rather than grid-following). This incremental cost is assumed to be equivalent to five percent of the corresponding IASR capital expenditure cost. This follows the same approach as proposed status grid-forming BESS, which also have a five percent increase in capital cost applied to represent the additional cost of upgrade to grid-forming inverters.

It was assumed that all proposed and ISP-modelled BESS projects will be commissioned in grid-forming mode from day one (i.e., supported by a non-network system security contract with Transgrid).

5.3.3. Existing plant without synchronous condenser mode

The costs for existing coal and gas plant have come primarily from the 2023 IASR. Verification of costs and feasibility of gas and hydro units has been assessed by an independent consultant, GHD, as outlined in Appendix E.

Where costs are not available in the 2023 IASR assumptions (e.g., start-up costs, installing clutches, upgrading to add synchronous condenser capability etc), costs have come from either proponents or from the 2018 GHD cost and technical parameter review[38] undertaken for AEMO (as the most recent comprehensive assessment of technology costs and technical parameters).

[37] Where EOI proponents advised the conversion would take longer than 12 months, the proponent advised timing was applied.
[38] AEMO, September 2018, AEMO costs and technical parameter review

5.3.4. Existing plant with the option to operate in synchronous condenser mode

Transgrid received EOI submissions for existing hydro units with the ability to operate in synchronous condenser mode, either:

- with existing capability, which can operate interchangeably as a generator or in synchronous condenser mode without any modification (i.e., no capital cost required); or
- requiring upgrade, which can operate interchangeably as a generator or in synchronous condenser mode following an upgrade (i.e., incremental capital cost required).

For units with existing synchronous condenser capability, there is no CAPEX associated with the solution. For projects requiring an upgrade to enable synchronous condenser capability, proponent costs were used and verified by GHD. The fixed operating and maintenance costs (FOM) and variable operating and maintenance costs (VOM) used AEMO's 2023 IASR values, which was also validated by GHD. The IASR value for VOM uses a cost per MW. However, for hydro units specifically, GHD advised that the primary driver of maintenance costs is the number of start/stop sequences which occur. The number of start/stops is assumed to be the same whether the plant chooses to provide system strength while generating, pumping or in synchronous condenser mode despite the MW value being different. Transgrid assumed the VOM on a per hour basis is consistent across modes.

For hydro units, there is not expected to be any material change in FOM cost between operating in generating, pumping or synchronous condenser mode. This is consistent with the methodology applied in the PADR, is supported by the 2018 GHD cost and technical parameter review and confirmed by GHD's independent advice during this RIT-T.

The 2018 GHD cost and technical parameter review was used to estimate values for auxiliary losses for hydro units in generating and pumping mode (one percent) and in synchronous condenser mode (four percent). This review was undertaken for AEMO and is considered the most recent comprehensive assessment for the cost of these parameters[39].

For gas units, there is not expected to be any material change in FOM cost to enable additional re-dispatch hours. GHD advised an increase in VOM to accommodate the additional re-dispatch hours forecast.

For compressed air storage, we have used proponent proposed costs, as AEMO's 2023 IASR does not cover these systems. For compressed air storage units which are committed or anticipated status, only the cost of the upgrade to enable synchronous condenser capability is included in the modelled CAPEX cost.

5.3.5. New build pumped hydro plant, gas, biomass

All synchronous pumped hydro units can provide fault current whilst operating in generating, pumping or in synchronous condenser mode (if applicable).

For all new-build pumped hydro, gas and biomass projects, Transgrid have used costs provided by proponents. If specific costs were not provided, costs from the 2023 IASR were assumed.

5.3.6. Non-network synchronous condensers

Non-network synchronous condensers proposals received were for new-build solutions, which means that the entire cost to deploy and operate was accounted for in the PACR market modelling (i.e. the same

[39] AEMO, September 2018, AEMO costs and technical parameter review

assumption applied for network synchronous condensers). The key costs including capex, FOM and VOM were all provided by the proponent.

5.3.7. Treatment of non-network system security contract costs

Proposed non-network system security contract costs net off equally between costs and benefits so do not impact the RIT-T NPV assessment,[40] and have been kept confidential. We note that the AER will now undertake an ex-ante assessment of the prudency and efficiency of eligible non-network system security contract payments[41] (on TNSP request).

Specifically, from 1 December 2024, the AER will make determinations when requested on whether expenditure under a TNSP's proposed non-network system security contract is consistent with the operational expenditure objectives, criteria, and factors to promote economic efficiency.[42] This will safeguard customers from excessive network support costs, which are not currently reflected in the RIT-T assessment of the preferred portfolio option (as only the underlying economic cost is modelled rather than the contract price), and provide greater investment certainty for TNSP's and proponents.

Through the PADR consultation period, we sought non-binding proposals for non-network system security contract costs from proponents. We undertook an assessment of these contract costs to identify whether we consider they would successfully pass the AER's assessment, drawing on the guidance set out in the AER's System Strength Guidance note[43].

In parallel and following publication of the system strength PACR, Transgrid will seek binding proposals from proponents of non-network solutions that have been identified as part of the preferred portfolio of solutions. There may be a difference between costs of system strength solutions modelled for this RIT-T (the economic cost) and the price obtained via the procurement process. If an outcome is not considered prudent and efficient by the AER or Transgrid, we will assess the need to deliver alternative non-network or network solutions. As such, a material divergence between the economic cost of a solution and the contract price for implementing that option is considered a RIT-T re-opening trigger.

[40] 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, October 2023, Regulatory investment test for transmission – application guidelines - Final decision

[41] As part of the 'improving security frameworks for the energy transition' rule change.

[42] AEMC, 28 March 2024, National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 - Rule Determination

[43] AER, December 2024, Efficient Management of System Strength Framework

6. Modelling approach and assumptions

Chapter summary

Transgrid uses a portfolio optimisation approach to form credible portfolios of individual system strength solutions (termed 'portfolio options') for this PACR, consistent with the approach in the PADR. This approach uses the Long-Term capacity expansion capability of PLEXOS to optimise and trade-off system strength solutions to minimise total system costs while also meeting system strength requirements. The assumptions have been refined or updated since the PADR to reflect the latest information available, and additional validation steps have been included to incorporate PSCAD™ modelling alongside PSS®E modelling.

Synchronous condensers were identified as a critical component of all portfolio options in the PADR, and the timing of their delivery was shown to have a significant impact on net market benefits and forecasted risks of system strength gaps. As such, PACR modelling has rigorously assessed the implications of the timing of when the first, and subsequent, synchronous condensers could be deployed. This was achieved by adjusting the optimised portfolio exclusively by the assumed 'first available' timing of synchronous condensers to derive additional portfolio options.

Key changes from the PADR and PADR Supplementary Report

- two portfolio options from the PADR were not progressed in the PACR, with PADR portfolio option 3 removed as the confidential proposal was withdrawn and PADR portfolio option 4 removed as it was notpreferred;
- multiple portfolio options created to test the impact of a variation in the timing of when synchronous condensers can first be deployed;
- incorporation of more realistic deployment schedules for additional synchronous condensers required in the same year, with an estimated 1.5-month stagger assumed between the operational date of each subsequent synchronous condenser (assuming multiple suppliers used);
- use of PSCAD™ to validate system strength contributions of individual solutions and the portfolios' capacity to support stable voltage waveform, in addition to PSS®E studies used to validate that minimum fault level requirements are met; and
- incorporation of more detailed representation of maintenance periods for hydro and gas generators and synchronous condensers.

The number of individual network and non-network solutions assessed in this RIT-T meant billions of potential individual solution combinations had to be considered and co-optimised across the six system strength nodes in NSW and the points of connection of forecasted 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'.

This section outlines the key features of the portfolio optimisation approach applied to develop portfolios of existing and new 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 (published alongside this PACR) includes additional detail on key elements of this approach, along with more detail regarding how the wholesale market modelling has been undertaken.

6.1. Portfolio optimisation process

Transgrid engaged Baringa to develop and undertake the portfolio formation process. The key aspects of this process are summarised in the subsections below. The portfolio optimisation process used for the PACR is broadly consistent with the PADR with a refinement to the inputs and assumptions underpinning the model.

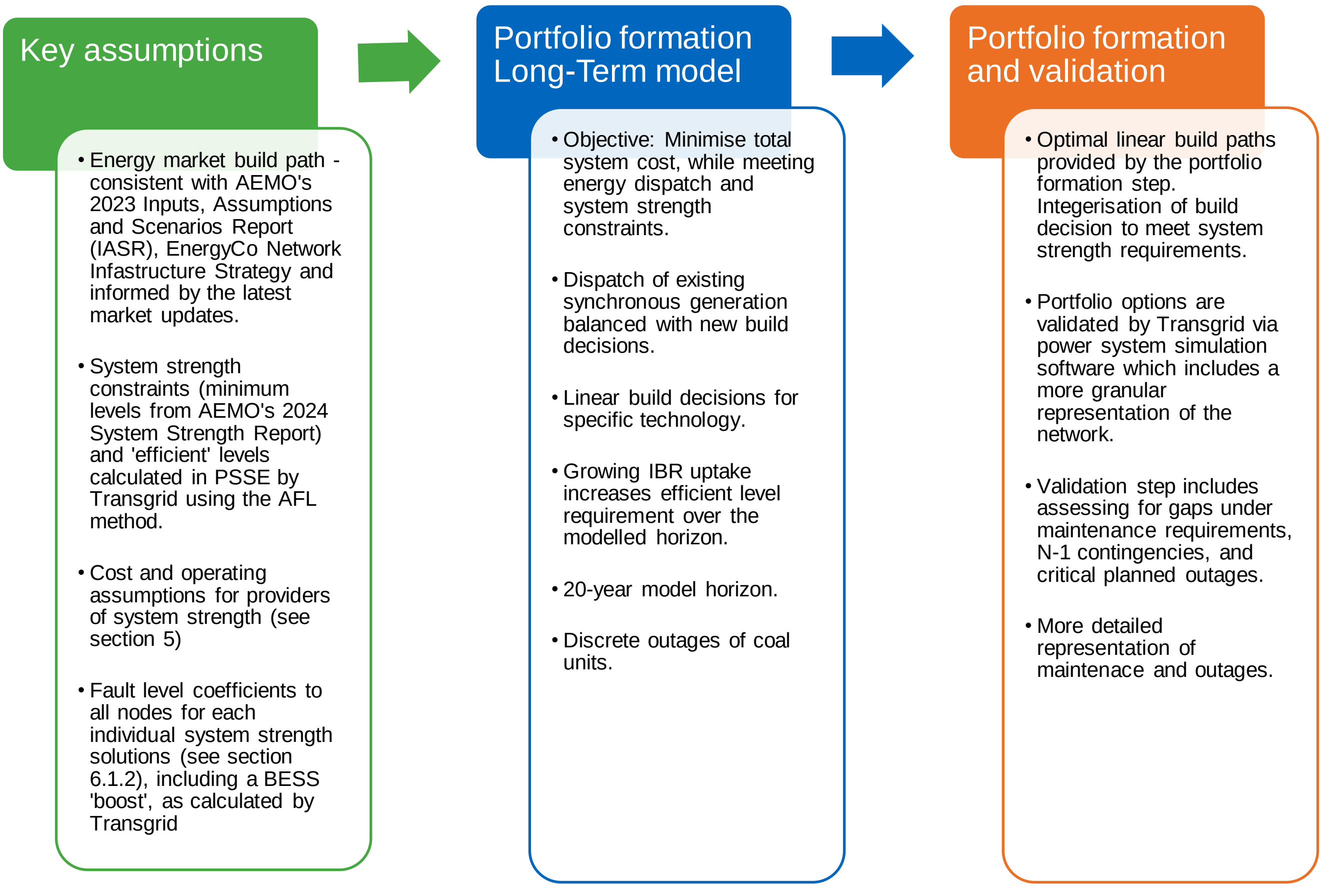
A Baringa constructed PLEXOS Long-Term model was used to form an optimal portfolio of individual system strength solutions. Mixed-integer programming techniques were used to compute a least cost, whole-of-NEM solution that progressively solves both the capacity expansion and unit commitment problems 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 individual solutions that minimised total system cost was determined as a 'portfolio option'.

6.1.1. Approach to forming a portfolio option

A portfolio option was formed based on a set of key assumptions which are input into PLEXOS's Long-Term Capacity expansion model and co-optimised to minimise total system cost while meeting system strength constraints and other network and operational constraints.

Figure 13. Portfolio formation process and key assumptions



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

- dispatching the market to meet energy demand;
- re-dispatching synchronous machines to satisfy system strength constraints; and
- new build solutions for system strength.

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

Transgrid has assessed each portfolio option against the ISP Step Change scenario consistent with how our system strength obligations are set by AEMO. Input assumptions are consistent with those used within AEMO's Integrated System Plan; detailed input assumptions can be found in Appendix G.

6.1.2. Calibration of PLEXOS inputs and validation of PLEXOS outputs via PSS®E and PSCAD™

The portfolio optimisation approach was required by the magnitude of individual solutions assessed. Transgrid used detailed power system modelling to represent dynamic and non-linear fault current contributions of each solution as 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.

The fault level coefficient for grid-forming BESS was multiplied by a 'boost factor' to account for the strong contribution of this technology for supporting stable voltage waveform, which is not accounted for using the AFL method. For the PADR, a boost factor of 3.1 was assumed for all grid-forming BESS (based on preliminary PSCAD studies). Following detailed PSCAD analysis undertaken on multiple inverter-supplier models [44], boost factors were calculated and applied in the PACR with a range between 2.6 and 4.1 based on the grid-forming inverter supplier. For more details see Appendix B.3.

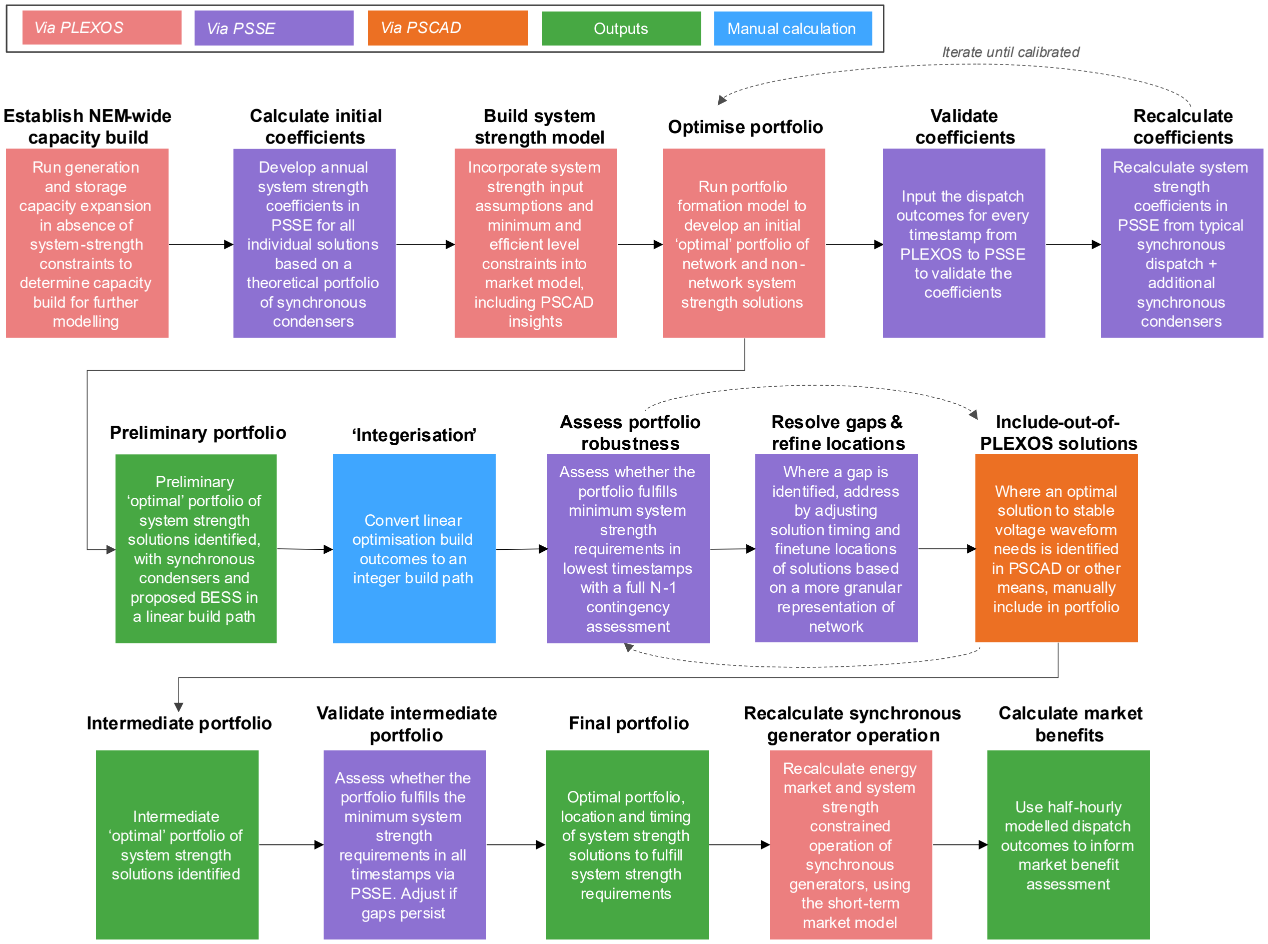
To validate the output of PLEXOS' portfolio optimisation met the power system's needs, PLEXOS results were analysed within PSS®E for the minimum level requirements. This process involved hundreds of thousands of power system modelling simulations.

For the PACR, we used PSCAD™ to validate portfolios of individual system strength solutions to meet the efficient level requirements in regions where high IBR uptake is forecast in the coming five years (such as South West REZ and Hunter-Central Coast REZ). Analysis used a four-state (New South Wales, Victoria, Queensland and South Australia) wide-area network models.

Figure 14 shows the iterative process that occurred to arrive at the optimised portfolio options.

[44] Aghanoori et. al., 2025, Comparison Between Synchronous Condensers and Grid Forming BESS in Providing System Strength Support to IBRs in Weak and Strong Power Systems Using EMT Simulation

Figure 14. Overview of the modelling approach for this RIT-T



Appendix B provides additional detail on the 'post-processing' that was done to the PLEXOS outputs. This includes the feedback loop for the system strength solution coefficients in PSS®E, the identification of gaps 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.

6.2. Synchronous condenser availability date has been varied to derive additional portfolio options

Synchronous condensers were identified in the PADR as a key part of all portfolio options, and changes in the assumed timing of synchronous condensers were shown to have a high impact on the net market benefits and forecasted risks of system strength gaps. The timing of the deployment of synchronous condensers is contingent upon the duration of the regulatory and procurement processes to progress the investments identified in this RIT-T as well as lead-times offered by suppliers.

The earliest credible timing for synchronous condensers has been updated from the assumed July 2028 date in the PADR, to a range of credible timing between:

- March 2029, the earliest credible, yet optimistic timing, assuming fastest progression through regulatory and procurement processes; and

- February 2030, the estimated timing following a standard progression through regulatory and procurement process.

This timing been revised since the PADR to reflect latest information obtained via supplier engagement, as well as latest estimates of the duration of the system strength RIT-T and Contingent Project Application (CPA) process, through internal workshops of subject matter experts across regulation, procurement and project development.

We assumed the commissioning of each subsequent synchronous condenser is staggered in 1.5-month intervals. This reflects the practicalities when delivering a portfolio synchronous condenser, informed by engagement with suppliers of synchronous condensers. This is an update to the methodology since the PADR, which assumed multiple synchronous condensers could be deployed at once. The staggered delivery of synchronous condensers was completed as a post-processing adjustment, discussed in Appendix B.5. The actual delivery schedule is subject to market constraints and will be reviewed as appropriate following the formal procurement process.

6.3. Developing an enhanced portfolio option

For the PACR, we have opted to develop an ‘enhanced’ portfolio option to make the portfolio more resilient to a divergence between the future state of the world and the assumptions underpinning this RIT-T. This approach seeks to mitigate against the risk of future uncertainties, including unexpected coal outages, earlier than expected retirements, underperformance of grid-forming batteries, unsuccessful modifications of synchronous machines or delays to transmission infrastructure.

This is achieved by manually bringing forward one or more synchronous condensers relative to the timing identified through the portfolio formation process (which forms a portfolio that has ‘just enough’ system strength and delivers solutions ‘just-in-time’). This approach was introduced in the PADR Supplementary Report, and the justification is discussed in Section 7.7.

6.4. Accelerating synchronous condenser procurement

In the PADR, we introduced and consulted on the benefits of ‘accelerating’ synchronous condenser timing ahead of the timing identified as credible (Section 6.2). Acceleration is expected to only be feasible if Transgrid commences procurement of synchronous condensers prior to the conclusion of the RIT-T and AER’s approval of a contingent project application.

Although ‘accelerated’ delivery of synchronous condensers is not currently considered credible, it is considered possible. Transgrid is actively pursuing options to enable the accelerated procurement of synchronous condensers.

Two portfolio options are designed to test the effect upon net market benefits of accelerated procurement, through manual adjustments to the earliest timing of synchronous condensers.

6.5. Treatment of Central West Orana REZ, Stage 1

The treatment of the Central West Orana REZ has not changed since the PADR. System strength for stage 1 of the Central West Orana REZ (for 5.84 GW of IBR) will be centrally remediated by the REZ network operator ‘ACEREZ’. Transgrid has participated in Joint Planning activities with EnergyCo to ensure an efficient whole-of-network solution.

While the 5.84 GW of IBRs has effectively been 'removed' from Transgrid's obligations, Transgrid has included the 5.84 GW of IBRs within Central West Orana REZ in the market modelling (as the energy market would otherwise be affected) and included the Central West Orana REZ system strength remediation as a modelled project (i.e. including it in the base case and all portfolio options). This enables the modelling to capture the interplay of fault current provision that flows between the REZ and the NSW backbone. Transgrid has modelled the self-remediation of Central West Orana REZ Stage 1 so that the renewables within Stage 1 do not require additional system strength support from the Transgrid backbone.

Transgrid expects regulations to be made by the NSW Government that expressly override Transgrid's obligations under the NER in relation to the system strength for the first 5.84 GW of IBR within Central West Orana REZ.

At this stage, Transgrid does not have confirmation on who will remediate IBR beyond the first 5.84 GW within Central West Orana REZ. As such, this PACR assumes that Transgrid is responsible for remediating future IBRs in the REZ.

6.6. Detailed power system studies to finetune the portfolio options

In developing the PACR modelling, Transgrid undertook PSCAD™ studies to validate the use of the AFL method to approximate system strength requirements, as described in Appendix B.2. This process showed that the AFL method is a useful long-term planning proxy for stable voltage waveforms support.

However, the validation process highlighted on a more granular scale that individual regions may perform either worse or better than expected under the AFL method. Specifically, regions with high amounts of IBR and which are electrically distant from other parts of the transmission network are expected to be less accurately represented by the AFL method for the efficient level. This was identified in the PADR for Broken Hill which has been treated separately to the portfolio optimisation entirely.

For the PACR, South West REZ and the Hunter-Central Coast REZ have been identified as regions considered prudent for detailed PSCAD™ assessment as they are intended to host significant levels of IBR. The South West REZ was included in the NSW-wide optimisation in PLEXOS (via the AFL method) and also has undergone a parallel PSCAD™ assessment of the system strength solutions required to support stable voltage waveform. The Hunter-Central Coast REZ was assessed outside of the portfolio optimisation process. Further details for each region are discussed in the sections below.

6.6.1. South West REZ

Transgrid is responsible for providing sufficient system strength for South West REZ. The region surrounding Dinawan substation (being built as part of Project Energy Connect) has been identified as the central hub for the South West REZ. Dinawan is electrically distant from the nearest system strength nodes (Darlington Point and Buronga) and the RIT-T IBR forecast includes 2.6 GW of new IBR in the region.

Transgrid has undertaken additional network studies, primarily using PSCAD™, to assess the system strength portfolio's capacity to maintain stable voltage waveform. The assessment focussed on years of higher IBR growth and periods expected to exhibit the lowest levels of system strength. Using insights from PSCAD™, an out-of-model assessment of the various system strength solutions available in the region and a comparison of the lowest cost per MVA solution which meets the need was undertaken. Transgrid also used the out-of-model assessment to incorporate the impacts of any renewable constraints in the REZ on total system costs, prior to the entry of new-build system strength solutions, further explained in Appendix J.

6.6.2. Hunter-Central Coast REZ

Ausgrid is developing the Hunter-Central Coast REZ to facilitate the connection of approximately 1.8 GW of new renewable generation and storage projects, with a network transfer capacity of 1 GW[45]. Transgrid's IBR forecasts estimate that approximately 1.4 GW of IBR will connect into the REZ by 2027/28. Transgrid is responsible for providing sufficient system strength for the Hunter-Central Coast REZ.

Similar to the South West REZ, Transgrid has undertaken additional network studies on Hunter-Central Coast REZ, primarily using PSCAD™, to assess the system strength portfolio's capacity to maintain stable voltage waveform. Network studies used a four-state (NSW, QLD, VIC and SA) wide-area model of the network forecasted in 2028/29 to assess stable voltage waveform in the Hunter-Central Coast REZ. The year 2028/29 was studied in detail, as the most likely year that new system strength solutions could delivered.

Through Joint Planning, Ausgrid provided a network topology and details of the REZ for Transgrid to assess the system strength solutions required using PSCAD™. An assessment of the least-cost solution was conducted separately to the portfolio optimisation process. Modelling has shown to be cost-effective, solutions are required to be located on the Ausgrid network, close to the expected point of connection of future IBR. As such, only non-network solutions were considered, including targeted grid-forming BESS or non-network synchronous condensers.

6.6.3. Broken Hill

Transgrid's IBR forecast used for the PACR modelling projects 237 MW of new IBR to connect surrounding Broken Hill from 2027/28. Power system studies (using the AFL method) indicate that approximately 493 MVA of additional fault current contribution is required at Broken Hill to support this level of additional IBRs. This forecast IBR capacity has increased slightly since the PADR and has been deferred by one year. For details on the changes to the IBR forecast, see Section 2.2.

Transgrid has not changed its approach from the PADR to identify system strength solutions at Broken Hill. As Broken Hill is electrically distant to the nearest system strength node at Buronga, Transgrid has assessed the least-cost solution to meet this need separately to the portfolio optimisation process and included the preferred solution as part of each portfolio option.

The solutions available are:

- Modifications of the solution that will be deployed to meet Broken Hill's reliability needs (driven from the Maintaining reliable supply to Broken Hill RIT-T)[46] to enable synchronous condenser mode operation;
- synchronous condenser(s); and
- new 'targeted' grid-forming BESS(s).

6.7. Estimating portfolio option market benefits

The methodology for estimating net market benefits across portfolio options has not changed since the PADR.

[45] EnergyCo, 2025, Hunter-Central Renewable Energy Zone - Summary of EnergyCo's network recommendation
[46] Transgrid, 2022, Maintaining reliable supply to Broken Hill RIT-T

The Value of Customer Reliability is used to quantify the estimated value of avoided involuntary load shedding for each option. We have adopted the AER's most recent assumptions for the VCR for the purpose of this assessment, published in December 2024[47]. This is an update from the value applied in the PADR analysis, which used the previous values published by the AER.

For details of the methodology to estimate option market benefits for each market benefit class refer to Appendix F.

[47] AER, December 2024, Values of customer reliability - Final report on VCR values

7. Portfolio options and net market benefits to identify the preferred credible portfolio option

Chapter summary

This chapter presents the composition and net market benefits of portfolio options 1 and 2. Portfolio option 1 ('basic portfolio') was designed to identify the combination of individual system strength solutions to meet the system strength need in NSW with minimal margin of error to manage uncertain future conditions. This portfolio option follows the same methodology as portfolio option 1 in the PADR, with updated inputs and assumptions.

Portfolio option 2 ('enhanced portfolio') was constructed to test the difference in the costs and benefits of bringing forward one synchronous condenser identified as required in 2031/32 in portfolio option 1 to 2029/30. This adjustment increases resilience to the power system against risk of future uncertainties. This approach is an extension of the assessment presented in sensitivity three of the PADR Supplementary Report.

Both portfolio options assume that network synchronous condensers are available from March 2029, representing the earliest credible timing. This timing assumes a fast progression through the regulatory and procurement processes. Subsequent synchronous condensers required in each year are staggered in 1.5-month intervals to reflect real-world practicalities of delivering a portfolio of synchronous condensers.

Each portfolio option is made up of a combination of the individual system strength solutions outlined in Section 4, with the key components being:

- **portfolio option 1: 'basic portfolio'** includes nine network (Transgrid) synchronous condensers and eight New England REZ synchronous condensers;
- **portfolio option 2: 'enhanced portfolio'** includes ten network (Transgrid) synchronous condensers and seven New England REZ synchronous condensers;
- **both portfolio options** also include:
  - 5 GW of grid-forming BESS by 2032/33 and 8 GW by 2044/45;
  - either four smaller non-network synchronous condensers (275 MVA) or 200 MW of grid-forming BESS to remediate the Hunter-Central Coast REZ, to be determined through a non-network procurement process;
  - 650 MW of synchronous generation upgrades to enable synchronous condenser capability; and
  - re-dispatch of synchronous generation to fill gaps in system strength;

Following the standard regulatory approval process and assumed lead times for synchronous condensers, the risk of gaps in system strength are observed in both portfolio options in 2027/28 and 2028/29. The risk of gaps is observed after the retirement of Eraring Power Station and prior to the entry of network synchronous condensers.

The net market benefits of the basic portfolio and enhanced portfolio are very similar, varying by only 0.3%; well within the margin of error for the assessment.[48] We consider that this justifies bringing forward one synchronous condenser earlier in the assessment period to increase the resilience of the portfolio to different states of the world relative to the assumptions modelled. As such, portfolio option 2 (enhanced portfolio) is considered the preferred credible option within this PACR.

This section describes the purpose, composition and net market benefits of portfolio option 1 (the 'basic portfolio') and portfolio option 2 (the 'enhanced portfolio'). These two portfolio options are designed to identify the optimal portfolio composition including the amount, location and timing (subject to the constraint of earliest credible timing of network synchronous condensers being from March 2029) of individual system strength solutions.

Figure 15. Summary of portfolio options 1 and 2

Objective: Identify optimal portfolio composition

Synchronous condensers are assumed to be first available from the earliest credible timing of Mar-2029

Option 1: Basic portfolio

Portfolio with minimal margin of error to manage uncertain future conditions.

Option 2: Enhanced portfolio

Added robustness by bringing forward one synchronous condenser required in 2031/32 in portfolio option 1, to 2029/30, to mitigate risk of future uncertainties, including unexpected coal outages or retirement, underperformance of grid-forming batteries, unsuccessful modifications of synchronous machines or delays to ISP transmission projects

Portfolio option 1 in the PACR follows the same methodology as portfolio option 1 in the PADR which was considered the most credible option. The names of the other portfolio options in the PACR do not link to the names used in the PADR. A discussion of how portfolio options have changed since the PADR is in Appendix H.

7.1. Summary of portfolio options 1 and 2

Both portfolio options contain a blend of non-network (e.g. grid-forming batteries, synchronous machine modifications, hydro, gas, coal) and network (e.g. synchronous condensers) solutions. Table 11 summarises the components of each portfolio option.

Network synchronous condensers are assumed to be available to be in-service from March 2029. This is considered the earliest credible timing and assumes fast progression through regulatory and procurement processes. To reflect practicalities when delivering a portfolio of synchronous condensers, we have assumed subsequent synchronous condensers are staggered in 1.5-month intervals.

Table 11. Summary of the composition of portfolio options 1 and 2. All MW values are rounded to the nearest 50 MW.

[48] In present value terms, the $25 million difference in net market benefits is 0.28 per cent of the estimated net market benefits. There is also only a $21 million difference in capital and operating costs between these two portfolios (0.33 per cent difference). Both values are considered within the margin of error for this assessment.

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050MVA fault current), see note 1									
Portfolio 1	-	-	-	3	9	9	9	9	9
Portfolio 2	-	-	-	3	10	10	10	10	10
New England REZ synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)									
Portfolio 1	-	-	-	-	-	-	6	8	8
Portfolio 2	-	-	-	-	-	-	5	7	7
Hunter-Central Coast REZ system strength solutions									
All portfolios	-	-	Note 2	-	-	-	-	-	-
Upgrades to non-network synchronous machine to allow synchronous condenser mode (existing and new units) Cumulative capacity (MW)									
All portfolios	50	50	300	650	650	650	650	650	650
Grid-forming BESS Cumulative capacity (MW)									
All portfolios	-	1,350	3,250	3,650	4,150	4,800	4,800	4,950	8,150

Note 1: Synchronous condensers with a fault level contribution of 1,050 MVA have been assumed for this analysis. If synchronous condensers with a fault level contribution of <950MVA are selected through Transgrid's procurement process (calculated using unsaturated reactance), an additional one synchronous condenser is required in 2029/30 in the Sydney West or Newcastle regions (under both portfolio option 1 and 2).

Note 2: Studies have identified four non-network synchronous condensers (275 MVA fault current contribution each) or 200 MW of grid-forming BESS are required to meet the efficient level requirement in the Hunter-Central Coast REZ, the cost of each are within a margin of error. Transgrid has opted to identify the preferred system strength solution and proponent for this REZ in the procurement process (which will be contracted as a non-network option).

While the portfolio of grid-forming batteries is aggregated by nameplate capacity for ease of communication, their stable voltage waveform provision is heavily influenced by the control logic and tuning of the inverter. As a rough approximation, our modelling identifies that 5 GW of grid-forming batteries (by 2032/33) provides the equivalent stable voltage waveform support of seventeen synchronous condensers. Detailed power system studies during the procurement of grid-forming batteries will be used to identify the optimal location, configuration, size and inverter brand to meet the need.

7.2. Summary of the risk of system strength gaps

The risk of gaps in the minimum level of system strength is projected until sufficient synchronous condensers are in-service, as shown in Table 12.[49] The estimated risk of gaps is similar under both portfolio options. The largest risks occur during periods of co-incident generation maintenance and forced outages and are exacerbated when transmission lines are taken out of service for maintenance or during network augmentations (for example to connect new REZ transmission infrastructure). These gaps present risks to the power system and consumers (possibly causing unserved energy).

[49] Note that this assessment of gaps in system strength is subject to the assumptions in the PACR market modelling. Gaps may be more or less in reality.

Table 12. Risks of gaps in system strength which cannot be filled across portfolio options 1 and 2

	Portfolio option 1	Portfolio option 2
2025/26	No gaps	No gaps
2026/27	No gaps	No gaps
2027/28	Risk of gaps	Risk of gaps
2028/29	Risk of gaps	Risk of gaps
2029/30	No gaps	No gaps
2030/31	No gaps	No gaps
2031/32	No gaps	No gaps
2032/33	No gaps	No gaps

There is a risk of gaps to the minimum level of system strength in both portfolio options for:

- up to 2% of time in 2027/28; and
- up to 1.5% of time in 2028/29 at all nodes other than Armidale, and up to 10% of the time at Armidale if critical planned outages of transmission lines occur as modelled.

Note that gaps observed during critical planned outages may be partially mitigated if outages can be co-ordinated with periods of high system strength.

Both portfolio options rely heavily on gas re-dispatch to meet the need in 2028/29. While our market modelling includes a daily NEM-wide gas constraint (consistent with AEMO's 2024 ISP model) and an additional pipeline constraint for two NSW gas generators (consistent with GHD advice), a comprehensive assessment of whether there is sufficient gas pipeline capacity and gas available is out of scope of this assessment. As such, the level of gas re-dispatch modelled in this year may be an over-estimation of possible re-dispatch of gas generators, potentially resulting in larger and/or more frequent than modelled gaps in system strength.

7.3. Summary of portfolio costs

The costs, including CAPEX and operational expenditure (OPEX) for each portfolio option, are tabulated in Table 13 (over the full 20-year horizon). All costs in the PACR are written on a 30 June 2024 dollar cost basis.

Portfolio option 2 has $21 million higher CAPEX and OPEX costs for synchronous condensers compared to portfolio option 1. This is due to the earlier procurement of one synchronous condenser and the higher build cost at the Liddell substation compared to the cost assumed in New England REZ (which uses costs at Armidale as a proxy).

Table 13. CAPEX and OPEX for each portfolio option out to 2044/45 in (undiscounted 2024/24 dollars, $m)

	Portfolio option 1	Portfolio option 2
Network (Transgrid) Synchronous condensers		
CAPEX	1,438	1,608
OPEX	141	157
Total	**1,578**	**1,765**

	Portfolio option 1	Portfolio option 2
New England REZ Synchronous condensers		
CAPEX	1,231	1,077
OPEX	102	89
Total	**1,332**	**1,165**
Hunter-Central Coast REZ system strength solutions		
CAPEX	181	181
OPEX	18	18
Total	**199**	**199**
Grid-forming BESS		
CAPEX	2,644	2,644
OPEX	476	476
Total	**3,120**	**3,120**
Unit upgrades to allow synchronous condenser mode operation		
CAPEX	18	18
OPEX	0	0
Total	**18**	**18**
Total cost (excluding re-dispatch)		
CAPEX	5,511	5,528
OPEX	737	740
Total	**6,248**	**6,269**

Relative to the equivalent option in the PADR (portfolio option 1), there is a material increase in the cost of portfolio option 1 out to 2044/45. This is particularly driven by:

- inclusion of 900 MW of proposed or targeted BESS which has the entire cost of CAPEX in the assessment. These projects are ideally located in areas of the network of high IBR uptake surrounding the Darlington Point and Armidale nodes that justifies the higher cost on a per MVA basis compared to cheaper anticipated/committed or ISP-modelled BESS in alternative locations;
- a material increase in the assumed cost of synchronous condensers as discussed in Section 5.1; and
- addition of Hunter-Central Coast REZ solutions, which were not required in the PADR (additional remediation was required as IBR on the distribution network receives minimal system strength from solutions located on the transmission network).

7.4. Composition of portfolio option 1: basic portfolio

Portfolio option 1 was formed through the portfolio optimisation methodology outlined in Section 6.1, consistent with a 'just enough' and 'just-in-time' approach (i.e. little margin for error). This is where the deployment of system strength solutions is perfectly timed to just meet the increasing need due to retiring synchronous generators or increasing levels of IBR. This approach is consistent with a 'least cost' optimisation approach, which has perfect foresight of future conditions.

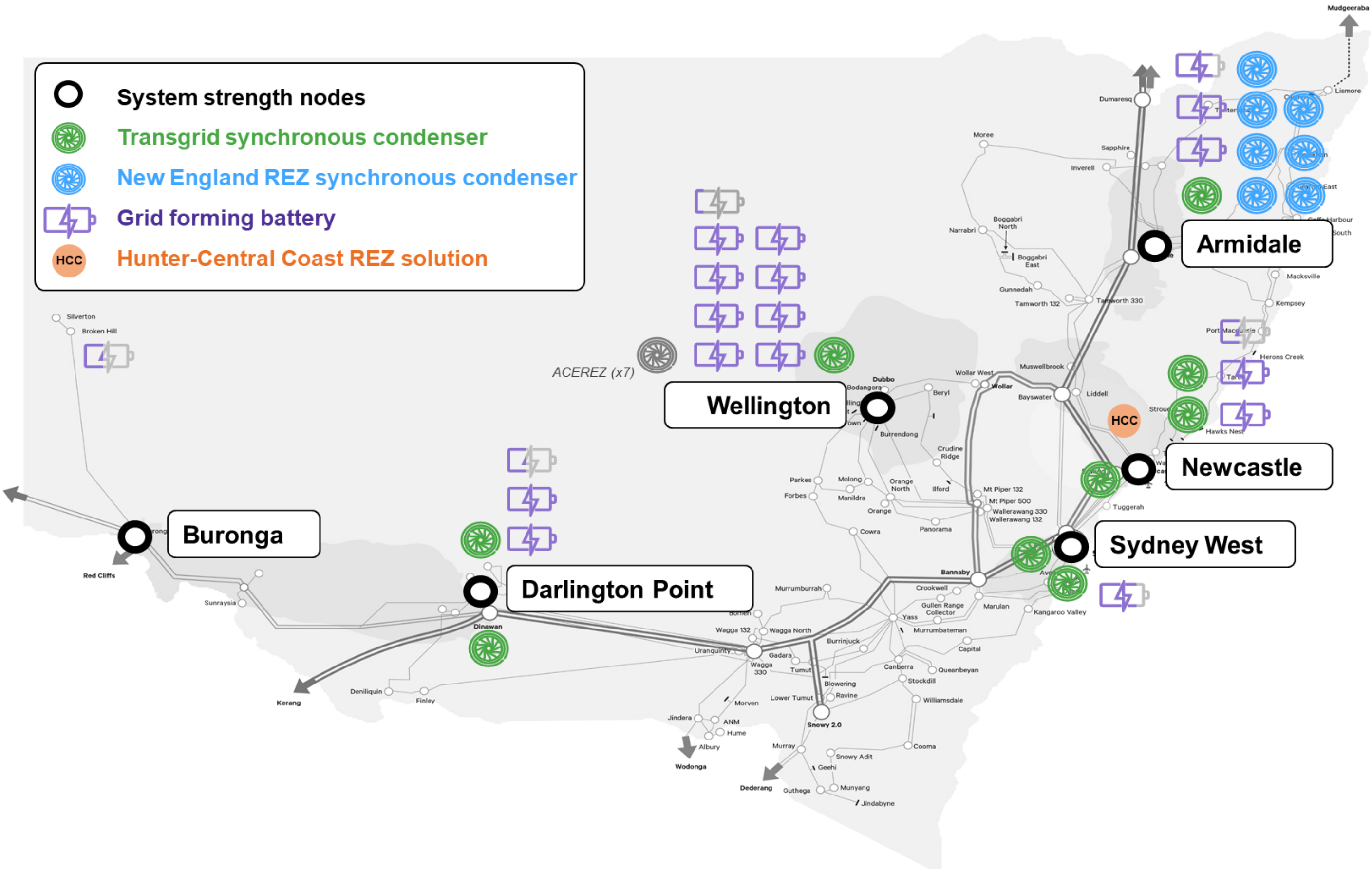
This portfolio assumes synchronous condensers are available from March 2029, which is considered the earliest credible synchronous condenser timing.

By 2032/33, the portfolio consists of:

- nine network (Transgrid) synchronous condensers, each providing 1,050 MVA fault current;
- eight synchronous condensers for remediation of the New England REZ, each providing 1,050 MVA fault current;
- either four small non-network synchronous condensers (275 MVA fault current) or 200 MW of grid-forming BESS in 2027/28 for Hunter-Central Coast REZ, with the preferred technology and proponent selected through a procurement process;
- 5 GW of grid-forming BESS;
- 650 MW of existing and new synchronous generation to be modified to enable synchronous condenser capability; and
- re-dispatch of existing hydro, gas and coal units.

The composition of new-build solutions in portfolio option 1 is presented in Figure 16 (excluding conversion of synchronous generation units for commercial sensitivity).

Figure 16. Indicative map of new-build system strength solutions in portfolio option 1 (where each grid-forming battery icon represents the equivalent contribution to the efficient level of system strength as one synchronous condenser)



7.4.1. Synchronous condensers

Table 14 shows the location and timing of synchronous condensers included in portfolio option 1. Synchronous condensers are predominantly for the minimum level (with the exclusion of Dinawan and Hunter-Central Coast REZ solutions which are exclusively for the efficient level). As such, synchronous condensers are generally timed to meet an increase in the minimum level need driven by the forecast retirement of coal units.

Table 14. Synchronous condensers in portfolio option 1

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Location	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**By 2044/45**
Armidale	-	1	1	1	1	1	1
Newcastle	-	1	2	2	2	2	2
Eraring	-	-	1	1	1	1	1
Liddell	-	-	-	-	-	-	-
Kemps Creek	-	1	2	2	2	2	2
Wellington	-	-	1	1	1	1	1
Darlington Point	-	-	1	1	1	1	1
Dinawan	-	-	1	1	1	1	1

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Total network (Transgrid)	**-**	**3**	**9**	**9**	**9**	**9**	**9**
New England REZ	-	-	-	-	6	8	8

The number of synchronous condensers required by 2044/45 has decreased substantially from 26 in PADR portfolio option 1 to 17 in the PACR (excluding Hunter-Central Coast REZ). This is a result of the increased cost of synchronous condensers relative to grid-forming BESS since the PADR, as well as higher assumed ability for grid-forming BESS to support stable voltage waveforms (discussed in Appendix B.3). The use of grid-forming BESS for the efficient level of system strength has increased significantly in this PACR as discussed in Section 7.4.2 0.

Following the PACR, it may be necessary for Transgrid to re-evaluate and change the location of a network synchronous condenser to a different substation in the same region if site constraints, unexpected costs or complexities are identified during the detailed design and procurement phases for synchronous condensers. Synchronous condensers at Transgrid substations within the Sydney West, Newcastle or Hunter Valley regions are considered broadly interchangeable and would not materially affect the estimated net market benefits. This applies for synchronous condensers in all portfolio options.

Transgrid assumed equal sized synchronous condensers offering 1,050 MVA fault level contribution at the point of connection, to make portfolio optimisation and procurement more efficient. Although 1,050 MVA has been modelled for this PACR, during the procurement process this size may be adjusted based on tender responses, for example to unlock lower total costs or faster delivery. It is expected that the total fault level contribution from the procured portfolio of synchronous condensers should stay consistent with PACR outcomes. For example, Transgrid may select a supplier providing two 525 MVA fault level synchronous condensers as an equivalent solution to a single 1,050 MVA fault level solution.

The total estimated costs for network (Transgrid) synchronous condensers in present value terms (in 2023/24 dollars) are:

- $917 million in capital costs
- $60 million in operating costs

The total estimated costs for new-build solutions to remediate the New England REZ:

- $613 million in capital costs
- $39 million in operating costs

The total estimated costs for new-build solutions to remediate the Hunter-Central Coast REZ (cost of synchronous condensers and grid-forming BESS solutions are considered within a margin of error):

- $123 million in capital costs
- $8 million in operating costs

Transgrid will not commit to the procurement of system strength solutions for New England REZ until EnergyCo has decided on the party responsible for system strength remediation in the REZ. Transgrid will progress the procurement of non-network services for the Hunter-Central Coast REZ through a procurement process (either from synchronous condensers or grid-forming battery proponents).

Detailed studies of the South West REZ to finetune the portfolio

Detailed PSCAD™ studies observed that a stable voltage waveform could not be maintained post-contingency from 2029/30 following the deployment of 2.6 GW of IBR (IBR forecast discussed in Section 2.3.3).

Transgrid's network studies identified one of the critical contingencies impacting stable voltage waveforms is the loss of one of the two transformers at Dinawan. To maintain stable voltage waveform with this network topology, studies show that two synchronous condensers may be necessary.

However, at present there is uncertainty on the topology of the generator connections, IBR equipment manufacturers and tuning, as well as any additional transmission infrastructure required to support the REZ (for example, a third transformer at Dinawan to increase the transfer capacity of the region), which could decrease (or increase) the need for system strength support. As such, Transgrid considers it prudent and efficient to only install one synchronous condenser in Dinawan in 2029/30. We will continue to engage with connecting parties and EnergyCo in Joint Planning activities.

Detailed studies of the Hunter-Central Coast REZ to finetune the portfolio

Transgrid engaged in Joint Planning activities with Ausgrid to conduct network studies of the Hunter-Central Coast REZ, using latest information on the REZ topology and of expected generation within the REZ. Transgrid's results show very limited fault level is provided from transmission-connected system strength solutions, and as such distribution-connected solutions are essential.

Transgrid recognise the announcement[50] of the Hunter-Central Coast REZ occurred recently (December 2024) and there has not been sufficient opportunity for non-network system strength solutions to be proposed in the REZ (and specifically at Antiene). For this RIT-T, Transgrid has assessed both non-network synchronous condensers and generic grid-forming BESS solutions and identified that the cost of each solution is within a margin of error of each other and costs approximately $181 million in capital costs and $18 million in opex costs ($2023/24, undiscounted). Transgrid has opted to determine the preferred technology and proponent through engagement with non-network proponents via the procurement process.

For a synchronous condenser solution, analysis has identified that four non-network synchronous condensers from 2027/28 are required as part of the optimal portfolio (across all portfolio options). The synchronous condensers are optimally located at the new sub-transmission switching station named Antiene. Each synchronous condenser (rated capacity of approximately 45 MVA) was modelled to provide 275 MVA fault level contribution at the point of connection to the 132 kV network at Antiene bus (calculated using unsaturated reactance, a pre-fault voltage at 1 per unit and with 61 MWs of inertia). Smaller synchronous condensers are considered preferable to fewer but bigger synchronous condensers as there is greater redundancy during periods of maintenance and outages. Each synchronous condenser should be equipped with a flywheel to provide better stable voltage waveform support (and therefore providing significantly more than the 61 MWs modelled).

For the alternative grid-forming BESS solution, power system studies identified that 200 MW of grid-forming BESS[51] would be capable of maintaining stable voltage waveform. On the condition that the

[50] Ausgrid, December 2024, Ausgrid Powers Up The Future with Hunter-Central Coast REZ
[51] Assuming that the BESS meets the Automatic Access Standards of the NER.

largest contingency of the BESS (including but not limited to electrical, control or measurement device failure) results in at least 75% of its total installation capacity remaining in-service.

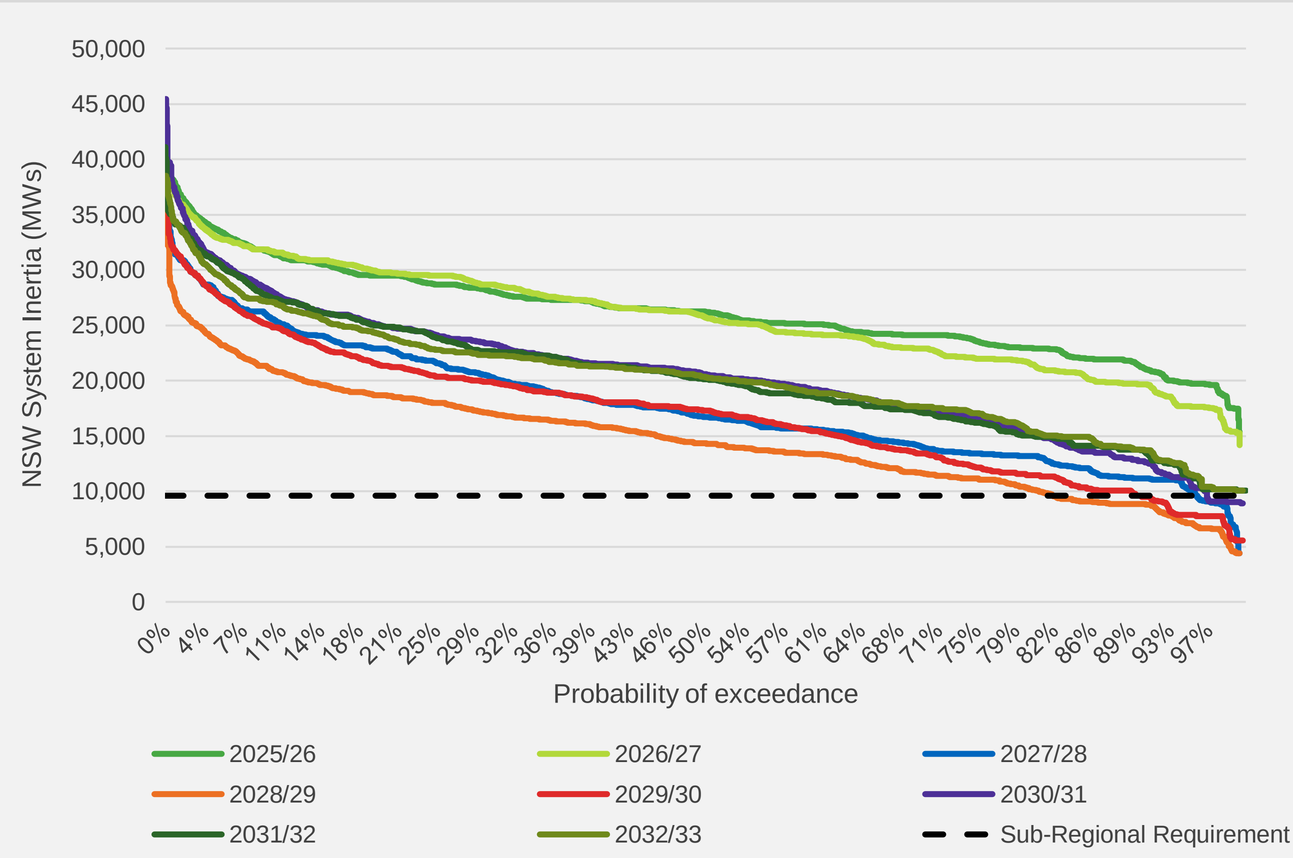
The efficient level need is from 2027/28 based on the projected IBR forecast for this RIT-T. However, Transgrid's assessment of each system strength solution's timing shows meeting this date may be difficult and system strength gaps may occur if IBR is built-out as forecast and elect to pay the system strength charge. As such, it is recommended to procure new system strength solutions, via a non-network procurement process, as soon as possible to minimise risks of renewable constraints in the region.

Benefit of synchronous condensers for inertia support

While Transgrid has not co-optimised system strength and inertia requirements, modelling indicates that the addition of flywheels to each network synchronous condenser (for the explicit purpose of stable voltage waveform support) will enable inertia requirements in NSW to be met without additional capital investment.

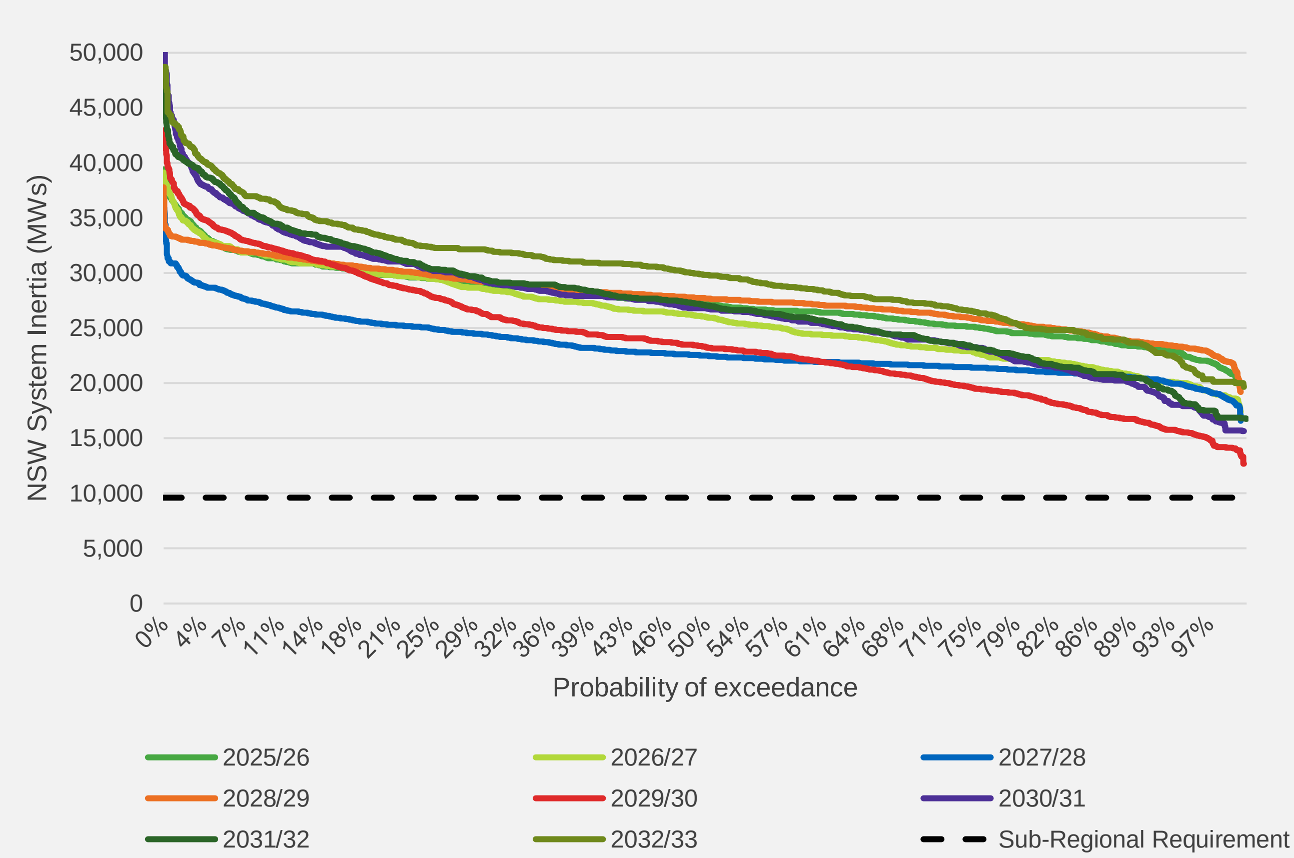
The analysis in Figure 17 presents declining levels of inertia projected over time in NSW as traditional synchronous units progressively retire from the energy market and in the absence of new sources of system strength.

Figure 17. Forecast inertia levels in NSW as coal generators retire and without new system strength support or re-dispatch (except for Central West Orana REZ synchronous condensers, which have been included as they are committed assets)



As new system strength solutions are deployed to meet system strength requirements (under portfolio option 2), or re-dispatch of synchronous machines for system strength prior to this, sufficient levels of inertia are projected to be available in NSW across the modelled horizon. This is demonstrated in Figure 18, with NSW system inertia exceeding the NSW sub-regional requirement of 9,600 MVAs in all periods.

Figure 18. Forecast inertia levels in NSW under portfolio option 2, where new sources of system strength are added and where synchronous machines are re-dispatched to provide system strength support as required



7.4.2. Grid-forming batteries

Portfolio option 1 includes 5 GW of grid-forming battery capacity by 2032/33, which is comprised of:

- 2,250 MW of ISP-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);
- 2,700 MW of EOI BESS including:
  - 1,800 MW of anticipated, committed and existing BESS; and
  - 900 MW of proposed BESS.

Of the grid-forming BESS identified, only the 900 MW of proposed BESS incurs the entire CAPEX of the solution in the modelling, as opposed to the incremental cost of anticipated, committed and ISP-modelled BESS.

Table 15 presents the location (by region) and timing of grid-forming BESS in portfolio option 1.

Table 15. Grid-forming BESS included within portfolio option 1, rounded to the nearest 50 MW

Grid-forming BESS (MW)									
Node	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2044/45**
Sydney West	-	250	250	250	250	250	250	250	250
Buronga	-	-	50	50	50	50	50	50	50
Newcastle	-	500	750	750	750	750	750	750	750
Armidale & New England REZ	-	200	600	600	600	700	700	850	2,300
Darlington Point & South West REZ	-	-	650	650	650	650	650	650	750
Wellington & Central West Orana REZ	-	400	950	1,350	1,900	2,450	2,450	2,450	4,050
Total	**-**	**1,350**	**3,250**	**3,650**	**4,150**	**4,800**	**4,800**	**4,950**	**8,150**

The overall amount of grid-forming BESS required in 2032/33 has increased by 150 MW since the PADR. The timing and location of grid-forming BESS required has also changed since the PADR, because of the revised IBR forecast. A key finding of the PACR relative to the PADR is the large increase in grid-forming BESS required by 2044/45, increasing from 4,800 MW total to 8,150 MW. This is a result of increased synchronous condenser costs relative to forecasted future grid-forming BESS costs, as well as their higher assumed system strength contribution (‘boost’ factors). The total estimated cost of all grid-forming BESS solutions under portfolio option 1, including the new build BESS and upgrade of existing, committed, anticipated, and ISP-modelled BESS, in present value terms (in 2023/24 dollars), is approximately $1,467 million in capital costs and $195 million in operating costs over the assessment period.

7.4.3. Upgrades to enable synchronous condenser capability

In addition to the new synchronous condensers, portfolio option 1 involves modifications to 650 MW of existing and committed synchronous machine capacity to enable operation in synchronous condenser mode (i.e. where they can provide system security services without needing to run in generation mode). All upgrades to enable synchronous condenser mode are required by 2028/29. These upgrades are common across all portfolios. The addition of a clutch (or equivalent modifications) presents a low-cost system strength solution for the minimum and efficient level of system strength, assuming the synchronous unit is existing, committed or anticipated (i.e. the cost of the solution for generation purposes is sunk).

In present value terms (in 2023/24 dollars), the upgrades to enable these units to operate in synchronous condenser mode are estimated to cost approximately $10 million in capital costs over the assessment period. There is no operational expenditure for units being upgraded to enable synchronous condenser mode.

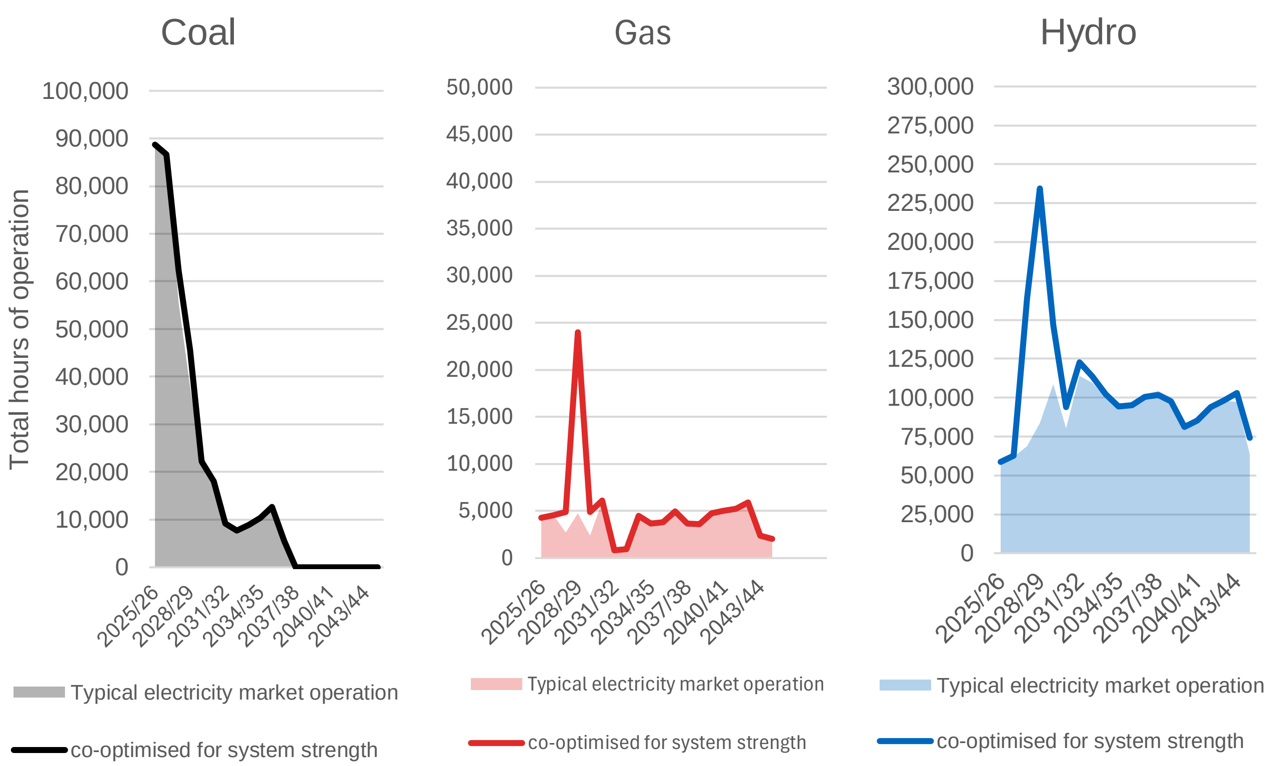
The generation forecast used in this PACR (and the 2024 ISP) does not forecast new-build gas until 2032/33, at which time the minimum level need will be met by the portfolio of synchronous condensers and typical electricity market dispatch of existing synchronous generating units. If new-build synchronous generation can be delivered earlier, the addition of a clutch to enable synchronous condenser mode may be a low-cost solution to substitute for synchronous condensers for the minimum level need, however only if this occurs prior to synchronous condensers being procured. More likely, clutches on new synchronous machines (e.g. new gas) may support the efficient level needs later in the assessment period.

7.4.4. Re-dispatch of existing and committed synchronous generators

Portfolio option 1 utilises an increase in the hours of operation of existing and committed synchronous generators to meet system strength requirements ('re-dispatch'), either in generation, pumping or synchronous condenser mode. Total hours of operation for each portfolio option (lines) are shown in Figure 19, compared with typical hours of operation expected for electricity market purposes only (shaded area).[52] All portfolio options rely on some hydro re-dispatch to meet the need in the first two years (no coal or gas re-dispatch). Most re-dispatch is required in 2027/28 and 2028/29 under portfolio option 1.

Additional operational hours peak in 2028/29, following the closure of Eraring and Vales Point Power Stations and prior to the deployment of sufficient synchronous condensers. Re-dispatch of hydro units predominantly occurs in synchronous condenser mode.

Figure 19. Re-dispatch required for portfolio option 1



There is a significant amount of gas re-dispatch in 2028/29 to contribute to meeting minimum level requirements. While the market modelling includes a daily NEM-wide gas constraint (consistent with AEMO's 2024 ISP model) and a specific additional pipeline constraint for two NSW gas generators (consistent with GHD advice), a comprehensive assessment of whether there is sufficient gas pipeline capacity and gas supply available was out of scope for this assessment. As such, and as outlined in

[52] Typical electricity market operation is determined through market modelling completed by Baringa as part of the portfolio optimisation process. Re-dispatch for 2025/26 and 2026/27 is calculated using Transgrid's system security limits advice and is identical across all portfolio options. This approach provides a refined shorter-term analysis on contributions of synchronous generating units to the stable operation and protection of the NSW transmission network. System strength limits advice has been provided to AEMO and will be applied by AEMO in the operational timeframe (via the 'Improving Security Frameworks' scheduler). Re-dispatch in the remaining years for all portfolio options is identified through the portfolio optimisation market modelling methodology. We note this approach has been applied to all re-dispatch charts in this PACR and is purely presentation (i.e., it has no bearing on the NPV assessment).

Section 7.2, the level of gas re-dispatch modelled in 2028/29 may be an over-estimation of the feasible dispatch of gas generators (which may result in larger than modelled system strength gaps), outlined in Section 7.2.

7.4.5. System strength solution at Broken Hill

Transgrid manually assessed the available system strength solutions for the Broken Hill region to support the stable voltage waveform of 237 MW of forecasted IBR (for conditions when Broken Hill is connected to the transmission system via the 220 kV transmission line, X2). Solutions assessed include:

- Modifications to the synchronous generating units of the solution that will be deployed to meet Broken Hill's reliability need to enable synchronous condenser mode operation, and 50 MW existing grid-forming BESS;
- Two 60 MVA rated synchronous condensers and 50 MW existing grid-forming BESS; or
- Two 60-90 MW grid-forming BESS and 50 MW existing grid-forming BESS.

Analysis has concluded that enabling synchronous condenser model operation for the solution planned to meet Broken Hill's reliability need is expected to meet the system strength need (when coupled with existing grid-forming BESS) and cost significantly less than two new build synchronous condensers or grid-forming BESS, whilst not providing materially different market benefits to these alternatives.

As such, this PACR confirms that enabling synchronous condenser model operation for the solution planned to meet Broken Hill's reliability need is the preferred outcome to meet the system strength need. Further technical studies are required to be completed prior to confirming the specific synchronous machine arrangement necessary to support system strength in Broken Hill. This solution is included across all portfolio options.

The preferred solution may not be delivered in time to meet the forecast efficient level need in 2027/28. This gap in stable voltage waveform support may result in constraints of new IBR, if firm projects materialise. Although the deployment of new grid-forming BESS may have a slightly earlier credible date of installation (less than one year earlier), the significant additional cost is not considered a prudent outcome, compared to the low marginal cost option of enabling synchronous condenser mode operation.

7.5. Composition of portfolio option 2: enhanced portfolio

Portfolio option 2 assesses the costs and benefits of bringing forward one synchronous condenser required in 2031/32 in portfolio option 1 to 2029/30, to increase the robustness of the system strength portfolio and to mitigate future uncertainties.

In line with the AER RIT-T guidelines and the AEMO ISP methodology, the PACR modelling uses a deterministic set of assumptions, aligned with the ISP Step Change scenario, that does not account for uncertainty surrounding future events. The modelling has 'perfect foresight' of future market conditions and variables are known by the model with certainty, and as such optimises to build 'just enough' solutions 'just-in-time'. As a result, there is a risk that our modelling does not capture the full range of potential outcomes that could result from uncertain future conditions.

The risks associated with the late or early deployment of system strength solutions are asymmetric in both magnitude and certainty. The costs of late deployment (or rather 'just-in-time' deployment where unexpected events occur) are disproportionately large and uncertain in nature compared to the relatively small and known additional cost of deploying solutions earlier.

The AEMC identified this asymmetric risk in the final system strength rule determination, concluding:[53]

"Following analysis undertaken through this rule change process, the Commission considers that a slight over-procurement of the service to support connecting IBR is likely to provide greater benefits for consumers than under-procurement. This is because due to the particular characteristics of system strength, the market impacts of having a unit less of the required amount of system strength is more significant than the cost of having an extra unit procured earlier than is needed"

The AEMC Reliability Panel further reinforced this position in their April 2025 submission to AEMO's Transition Plan for System Security[54], stating:

"The Panel emphasises the urgency of system security investment to keep pace with the transition… the Panel is of the view that to keep pace with the energy transition, security needs must be identified earlier so that timely investment can occur. Security risks are emerging faster than expected. For example, system strength and minimum system load have become critical risks earlier than expected, and market interventions have been needed to maintain system security."

"The risks of over- and under-investment are asymmetric. The risk of over-investment in security services, or investment earlier than needed, comes with much lower costs than under-investment or investment that is too late. Under-investment could lead to periods when the NEM cannot be securely operated. This means that proactive planning and identification of needs is required."

Examples of some future situations which lead to lower levels of system strength than anticipated include:

- unexpected or early retirement of synchronous generators;
- multiple coinciding forced or planned outage events of synchronous units and/or transmission lines and equipment outages (i.e. above which is currently considered in the modelled set of inputs and assumptions);[55]
- delays to, or unsuccessful commissioning of (or contracting with) non-network system strength solutions, such as upgrades of synchronous units to allow synchronous condenser mode or grid-following batteries upgrades to grid-forming capability;
- lower than expected performance of grid-forming inverters to provide stable voltage waveform support;
- drought years, lowering the availability of hydro generators that do not have synchronous condenser mode; and

[53] AEMC, 2021, Final Rule: Efficient management of system strength on the power system

[54] AEMC Reliability Panel, 23 April 2025, Letter to AEMO: Reliability Panel comments on AEMO's Transition Plan for System Security

[55] An example of this resulted in a recent system strength security direction by AEMO to maintain the power system in a stable operating state. On 15 November 2023, for the first time, AEMO issued a market intervention to manage power system security in NSW. At this time, there were five coal units offline for simultaneous planned and unplanned outages with a sixth unit scheduled to soon commence an outage. The remaining six synchronous generating units online in NSW would have been inadequate to maintain a secure operating state. AEMO intervened, directing a seventh NSW synchronous generating unit to delay maintenance and remain online to maintain power system security in NSW. Source: AEMO, 2023, Quarterly Energy Dynamics Report Q4

- delays to transmission augmentations and upgrades which otherwise would have helped to decrease network impedance and increase fault levels.

Transgrid assessed and consulted on the concept of a more robust ('enhanced') portfolio in the PADR Supplementary Report, published in October 2024.

7.5.1. Synchronous condensers and other new-build solutions

To improve the robustness of the portfolio of system strength solutions to uncertain future events, and in turn bring resilience to the power system, portfolio option 2 brings one synchronous condenser forward from the New England REZ in 2031/32 (as identified in portfolio option 1) to Liddell in 2029/30. This makes the portfolio more robust to meet minimum fault level requirements in 2029/30 and 2030/31 to different states of the world compared to the assumptions modelled under this RIT-T.

The synchronous condenser brought forward does not change the overall number of synchronous condensers however does incur a slight increase in CAPEX, in present value terms, given the earlier procurement and the variation in synchronous condenser costs between sites.

This manual adjustment was selected to provide additional resilience for minimum fault levels at Sydney West and Newcastle, prior to the delivery of the New England REZ. A synchronous condenser at Liddell still provides support to the New England REZ and provides additional support for any additional IBR that may connect to the transmission backbone in the Hunter Valley and Armidale regions.

Table 16 shows the location and timing of the synchronous condensers included in portfolio option 2.

Table 16. Synchronous condensers included in portfolio option 2

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Location	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**By 2044/45**
Armidale	-	1	1	1	1	1	1
Newcastle	-	1	2	2	2	2	2
Liddell	-	-	1	1	1	1	1
Eraring	-	-	1	1	1	1	1
Kemps Creek	-	1	2	2	2	2	2
Wellington	-	-	1	1	1	1	1
Darlington Point	-	-	1	1	1	1	1
Dinawan	-	-	1	1	1	1	1
Total network (Transgrid)	**-**	**3**	**10**	**10**	**10**	**10**	**10**
New England REZ	-	-	-	-	5	7	7

The total estimated costs for network (Transgrid) synchronous condensers in present value terms (in 2023/24 dollars):

- $1,023 million in capital costs
- $67 million in operating costs

The total estimated costs for new-build solutions to remediate the New England REZ:

- $534 million in capital costs
- $34 million in operating costs

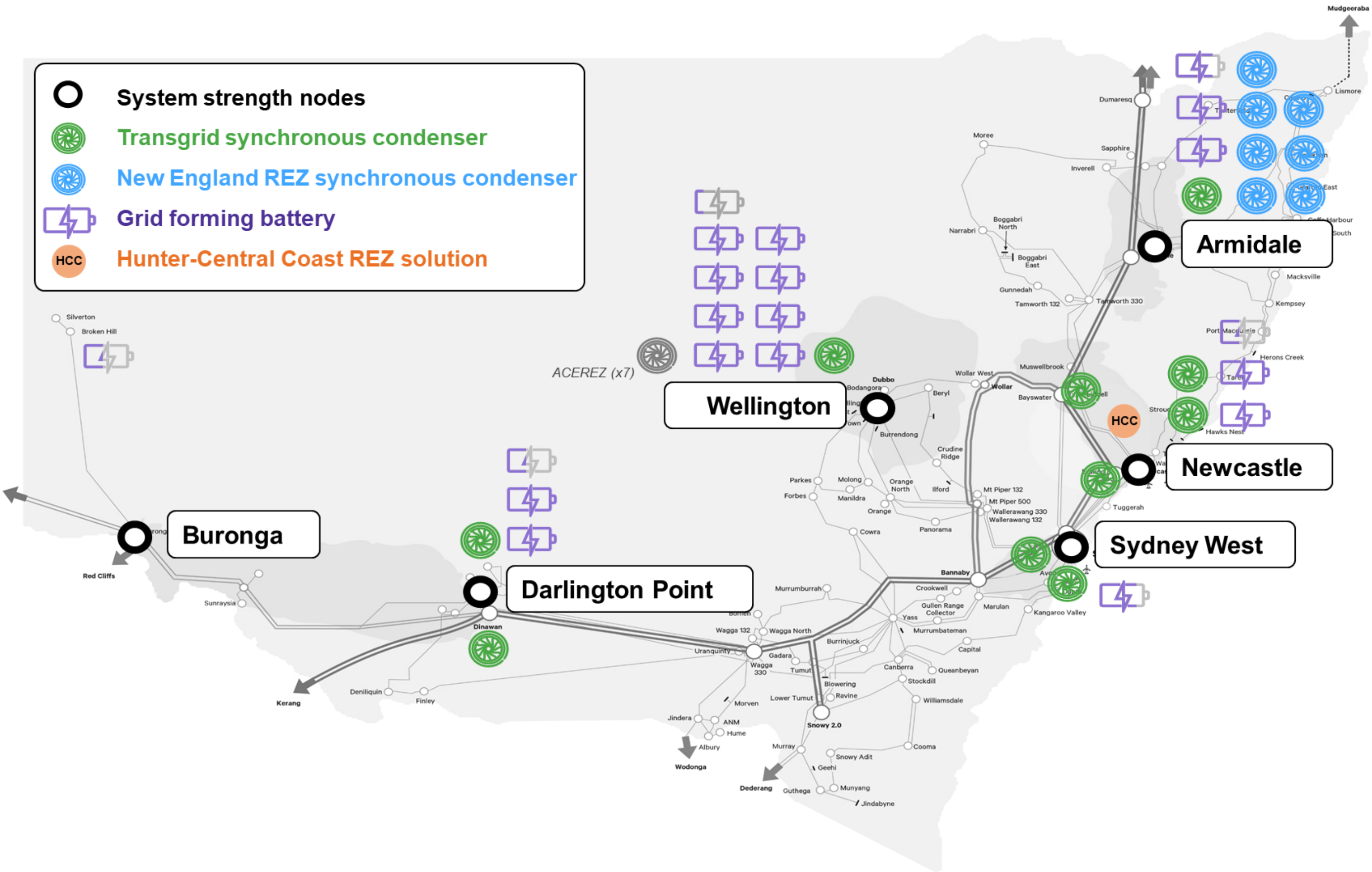
The total estimated costs for new-build solutions to remediate the Hunter-Central Coast REZ (cost of synchronous condensers and grid-forming BESS solutions to remediate the REZ are considered within a margin of error):

- $123 million in capital costs
- $8 million in operating costs

In present value terms, the total capital and operating costs of portfolio option 2 are $27 million and $2 million higher than portfolio option 1 respectively.

All other new non-network solutions remain identical to portfolio option 1 (including grid-forming batteries and modifications to synchronous machines). The composition of new-build solutions in portfolio option 2 is presented in Figure 20 (excluding modifications to synchronous machines for commercial sensitivity).

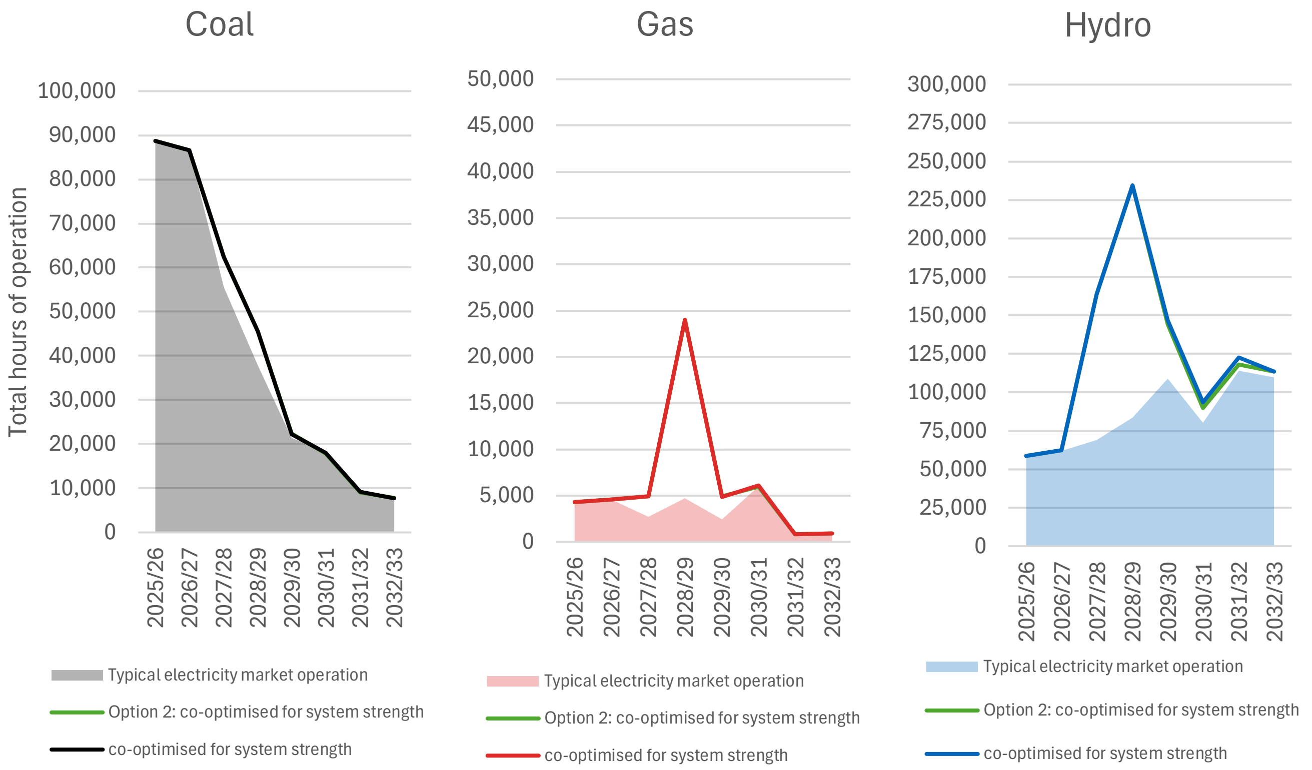
Figure 20. Indicative map of new-build system strength solutions in portfolio option 2 (where each grid-forming battery icon represents the equivalent contribution to the efficient level of system strength as one synchronous condenser)



7.5.2. Re-dispatch of existing and committed synchronous generators

Re-dispatch is similar between portfolio option 1 and portfolio option 2, except for a small reduction in the re-dispatch of all synchronous generators in portfolio option 2 between 2029/30 and 2031/32. This is a result of the Liddell synchronous condenser providing additional system strength surrounding the Sydney West, Newcastle, Armidale and Wellington nodes which therefore slightly reduces reliance on synchronous generators to change their typical energy market operation for provision of system strength services.

Figure 21. Re-dispatch occurring in portfolio option 2, compared to portfolio option 1



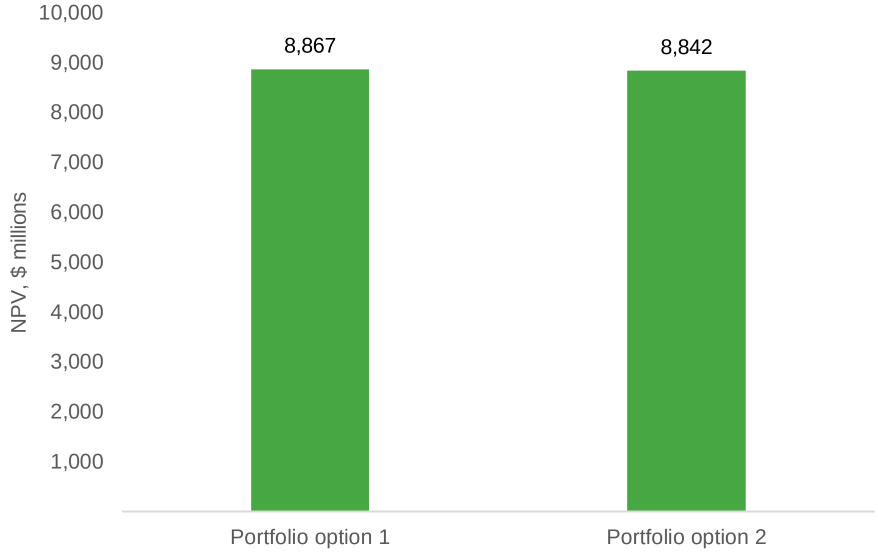
7.5.3. Forecast risk of gaps in system strength

Risk of gaps in the minimum level of system strength are observed in 2027/28 and 2028/29 in portfolio option 2 until sufficient synchronous condensers are deployed to meet the need. This result is identical to portfolio option 1, since the one Liddell synchronous condenser brought forward from the New England REZ is brought forward to 2029/30 after the gaps have been closed. The synchronous condenser cannot be brought further without changing the earliest deployment date (i.e. which remains March 2029) or removing the staggering of synchronous condensers.

7.6. Net market benefits of portfolio options 1 and 2

Figure 22 summarises the headline NPV results for portfolio option 1 and 2. Both portfolio option 1 and 2 are found to generate substantial net market benefits over the assessment period – at least $8.8 billion in net benefits, in present value terms.[56] The quantified net benefits of portfolio option 1 and 2 are within a margin of error for the assessment.[57]

Figure 22. Headline NPV results for portfolio option 1 and 2



The substantial benefits of both portfolio options (compared to the do-nothing base case) are driven primarily by avoided gaps in system strength from 2027/28 through to 2044/45, avoided generator fuel costs and lower emissions. The composition of estimated net market benefits for portfolio option 1 is compared against the base case in Figure 23.[58]

Under portfolio option 2, the expected net market benefits decrease by $25 million (in present value terms), compared to portfolio option 1. This decrease is driven primarily by the earlier deployment of the Liddell synchronous condenser which incurs a higher time-value-of-money CAPEX cost, as well as an assumed higher capital cost compared to a New England REZ synchronous condenser. This is partially offset by lower re-dispatch of synchronous machines. The difference in net market benefits is equal to 0.28% of the total net market benefits and the difference in costs is equal to 0.37% of the total portfolio option costs, this is considered well within the margin of error for this assessment.

[56] 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 portfolio options (as discussed in Appendix F.3). If this unserved energy is added to the analysis, the expected net benefit of all portfolio options would be significantly greater.

[57] In present value terms, the $25 million difference in net market benefits between these two portfolios is 0.28 per cent of the total net market benefits and a $21 million difference in capital and operating costs represents 0.33 percent of the portfolio option total cost.

[58] 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. Details of the base case are presented in Appendix I.

Figure 23. Composition of the estimated net market benefits for portfolio option 1, relative to the base case (NPV, $millions)

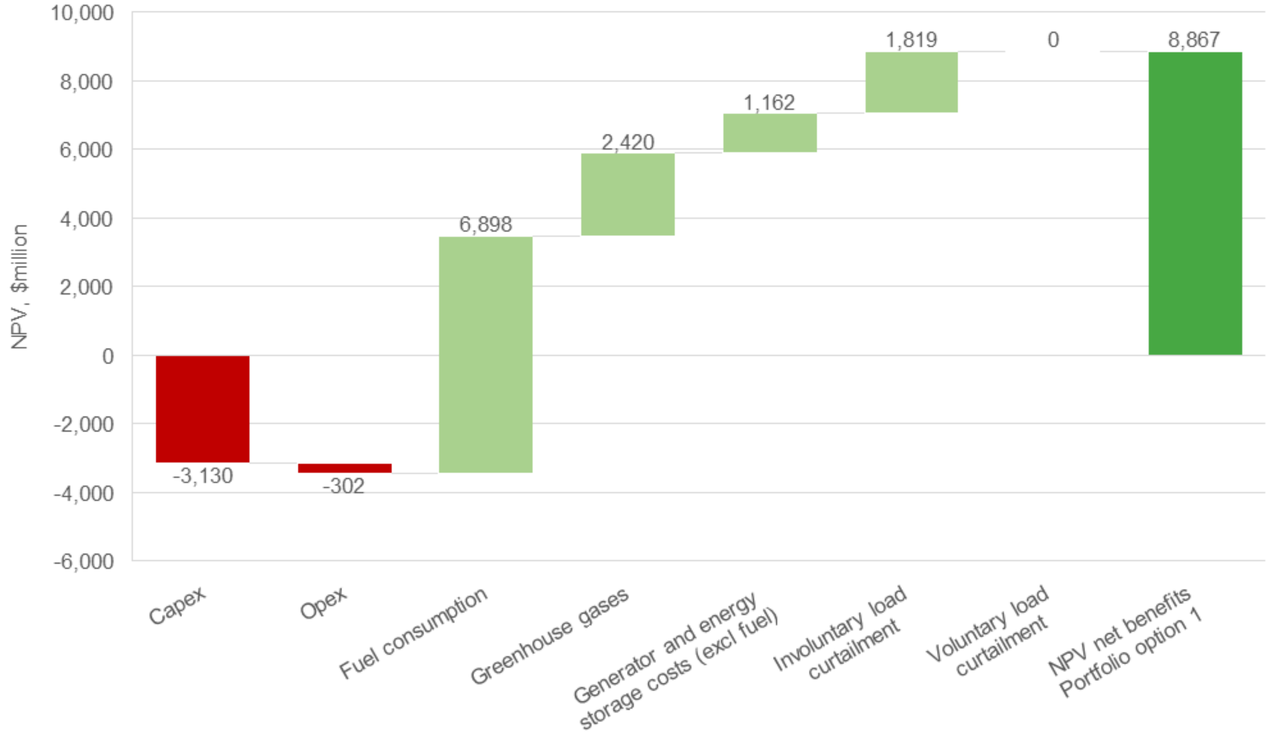
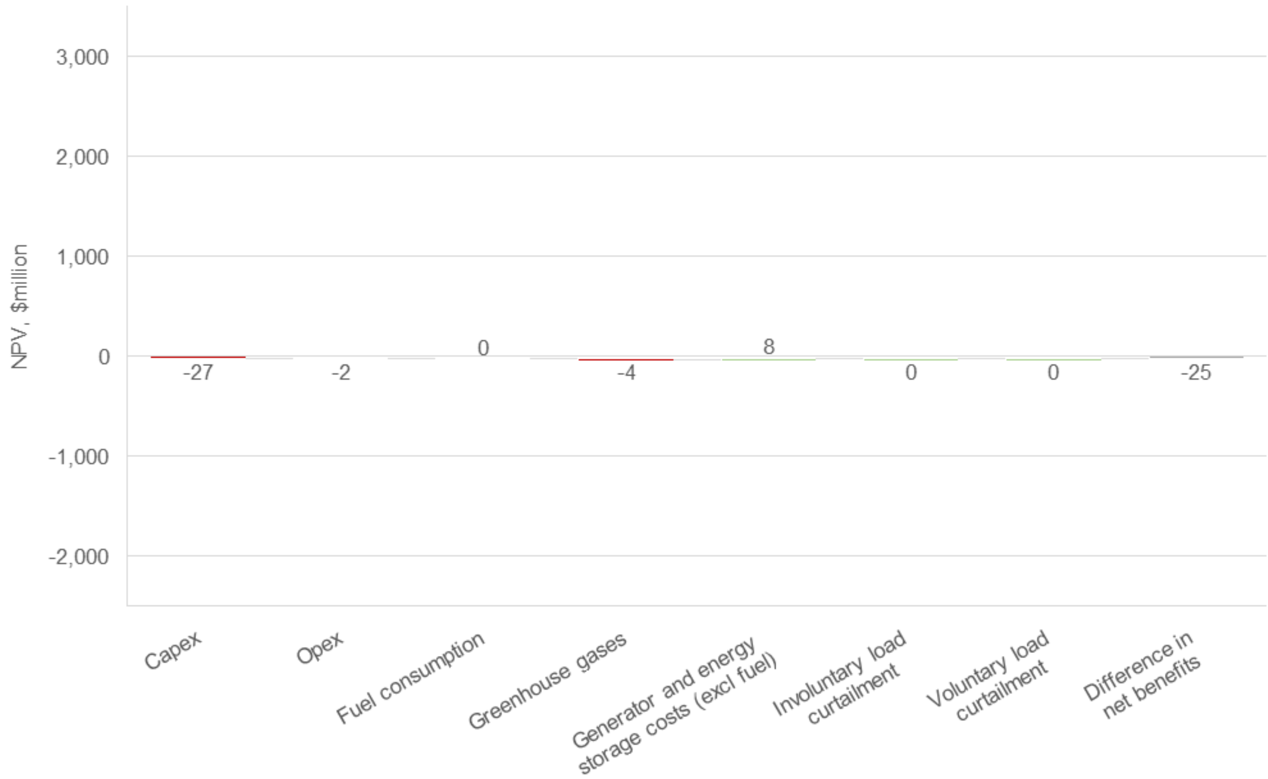


Figure 24. Key changes in the composition of the estimated net market benefits for portfolio option 2, compared to portfolio option 1



7.7. Portfolio option 2 (enhanced portfolio) is the preferred credible option

The net market benefits of the basic portfolio and enhanced portfolio are very similar and the difference between the two is within the margin of error for the assessment.[59]

Although a marginal decrease in quantified market benefits, one additional synchronous condenser between 2029/30 and 2031/32 would add material resilience to the power system during the energy transition (including for high impact, low probability events).

As the increased cost is relatively small and the unquantified benefit of added resilience are expected to be significant, we have selected portfolio option 2 (enhanced portfolio) as the preferred credible option for this RIT-T, representing the optimal portfolio composition of individual system strength solutions.

The selection of the enhanced portfolio over the basic portfolio seeks to achieve a lower-risk outcome for consumers, through the earlier deployment of one synchronous condenser, with minimum impact on total costs. Consideration of consumer risk preferences is consistent with AEMO's methodology to finalise its Optimal Development Path for the ISP, where further scrutiny is applied to high-ranking options to assess their robustness to changes in assumptions[60]. AEMO's Summary of consumer risk preferences indicate "residential consumers generally prefer earlier investment in electricity infrastructure, rather than later, if it only has a modest near-term bill impact"[61]. As the risks of over and under investment are asymmetric, it is considered prudent to incur a slight and measured earlier-procurement of system strength. The enhanced portfolio followed this approach.

The enhanced portfolio has assumed the earliest credible timing of synchronous condensers is from March 2029. Transgrid intend to deliver to this date, however external factors including the lead-time of synchronous condensers, the regulatory approval process with the AER and the dispute process for the PACR may delay the deployment of synchronous condensers. Transgrid has also modelled a portfolio option which assumes these factors prolong the regulatory and procurement process, leading to synchronous condensers being first available from February 2030. This is discussed in Section 8, in addition to an assessment of the impact of earlier synchronous condenser deployment upon the net market benefits.

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[59] In present value terms, the $25 million difference in net market benefits between these two portfolios is less than 0.3 per cent of the total net market benefits and the $21 million difference in cost if 0.37% of the total portfolio option cost.

[60] AEMO, June 2023, ISP Methodology

[61] AEMO, December 2023, Summary of consumer risk preferences project

8. Portfolio options and net market benefits to identify optimal portfolio timing

Chapter summary

In addition to portfolio options 1 and 2, we have designed three additional portfolio options to assess the impact of varying the first available deployment timing of synchronous condensers on the net market benefits (while holding the composition of the portfolios the same as portfolio option 2), specifically:

- **portfolio option 3** assumes first deployment of network synchronous condensers in February 2030, being the estimated timing for a standard progression through regulatory and procurement processes (where March 2029 in portfolio option 2 is considered the earliest credible, yet optimistic timing);
- **portfolio option 4** assumes partial acceleration with availability from May 2028 for the first five synchronous condensers and February 2030 for the remaining five; and
- **portfolio option 5** assumes full acceleration with availability from May 2028 for all ten network synchronous condensers.

Where multiple synchronous condensers are required in a single year, we have assumed the deployment of synchronous condensers are staggered in 1.5-month intervals, to represent practical realities of deployment.

The net market benefit analysis highlights the risk of late procurement and benefit of earlier procurement of network synchronous condensers, as can be seen by:

- a $2.2 billion decrease in net market benefits when Transgrid's synchronous condenser procurement is delayed from March 2029 to February 2030 (portfolio option 2 compared to 3);
- a $3.3 billion increase in net market benefits when the procurement of five network synchronous condensers is accelerated (portfolio option 4 compared to 3), or $1.1 billion compared to portfolio option 2; and
- a $3.4 billion increase in net market benefits when the procurement of ten network synchronous condensers is accelerated (portfolio option 5 compared to 3), or $1.2 billion compared to portfolio option 2.

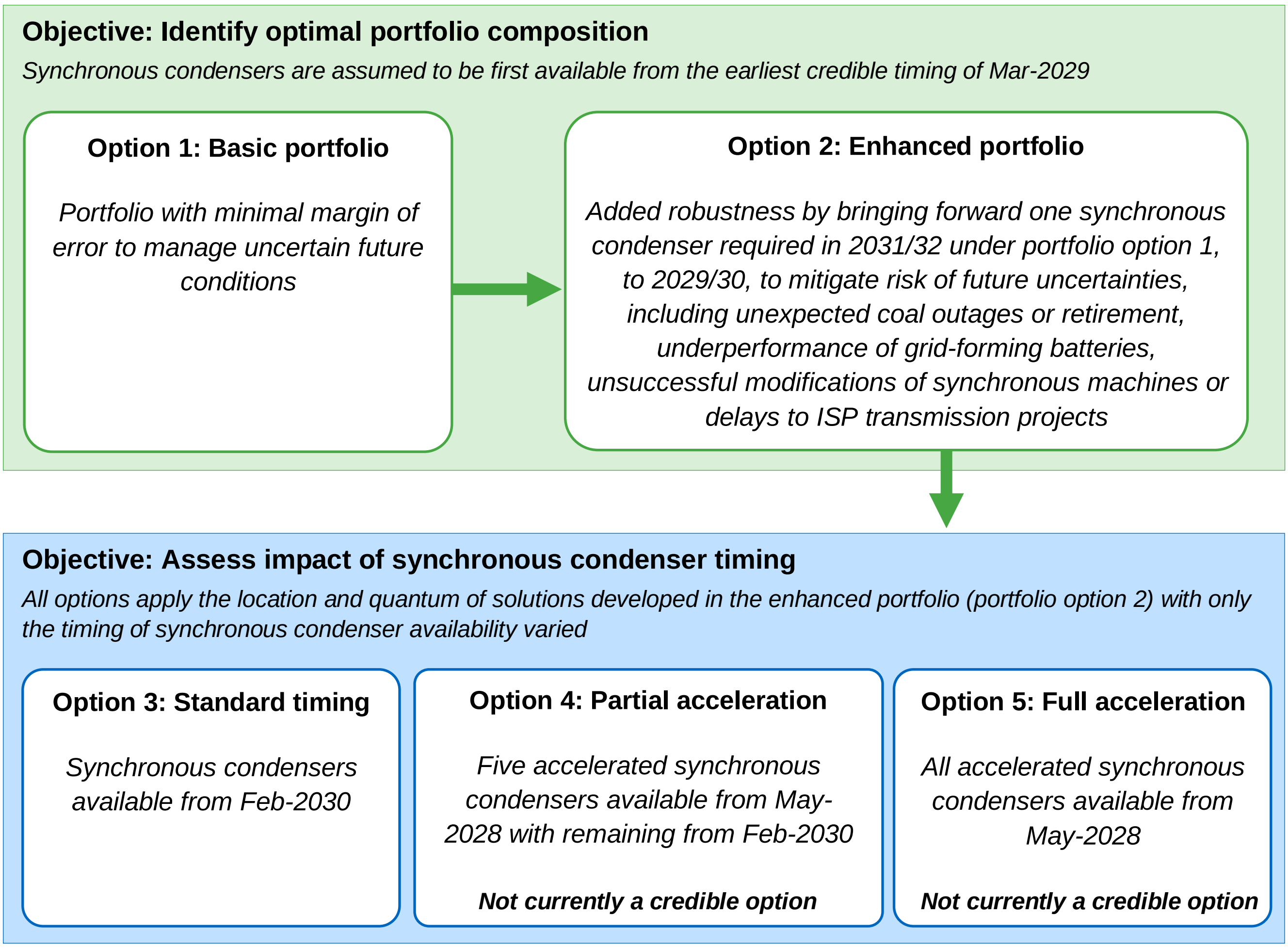
Full acceleration of network synchronous condensers (portfolio option 5) has $76 million higher net market benefits than partial acceleration (portfolio option 4). Transgrid expect the difference in net market of benefits to be even larger as portfolio option 5 is more resilient to a range of plausible events, including higher than expected IBR deployment, early coal retirements, more significant generator unplanned outages, delays to contracting with or availability of non-network options or delays to ISP transmission projects such as HumeLink, the Hunter Transmission Project or VNI West.

Portfolio option 2 is currently the preferred credible portfolio option. If the accelerated deployment of synchronous condensers is confirmed as credible, either portfolio option 4 or 5 would be the preferred credible option depending on the extent of acceleration possible. In recognition of the urgency of system strength requirements, Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders to enable the regulatory and procurement process to progress as quickly as possible. Following publication of the PACR, Transgrid will continue this work to deliver Transgrid synchronous condensers as soon as possible, with the goal to reduce power system security risks and maximise net market benefits.

Synchronous condensers were identified in the PADR to be a critical solution in all portfolio options, and changes to the assumed timing of synchronous condensers were shown to have a high impact on the net market benefits and forecast system strength gaps. This PACR assessed three different timings for the deployment of synchronous condensers, with timing reflecting latest information obtained via supplier engagement and incorporation of latest estimates of the duration of the system strength RIT-T, Contingent Project Application (CPA), procurement process and synchronous condenser lead-time.

The enhanced portfolio (portfolio option 2), being the preferred credible portfolio option, was manually adjusted to derive three additional portfolios, as shown in Figure 25. The objective of these three portfolio options is to assess the impact of synchronous condenser timing on the net market benefits of the enhanced portfolio.

Figure 25. Summary of portfolio options 1 – 5



Portfolio options 4 and 5 are not currently considered credible options. This is because the assumed timing of synchronous condensers under these portfolio options is earlier than considered credible based on Transgrid's assessment of the duration of the regulatory process and the lead times offered by suppliers. Portfolio options 4 and 5 are designed to test if there are additional benefits if earlier deployment of synchronous condensers was determined to be credible. Acceleration is only expected to be credible if Transgrid commences procurement of synchronous condensers prior to the AER's approval of a Contingent Project Application.

Table 17 shows the assumed timing for the first synchronous condenser in each portfolio option. To reflect practicalities when delivering a portfolio of synchronous condensers, we have assumed subsequent synchronous condensers required within the same year as the first must be staggered in 1.5-month intervals. This interval is informed by engagement with suppliers of synchronous condensers, which represents real-world limitations on delivery of multiple synchronous condensers simultaneously. The actual delivery schedule is subject to market constraints, and will be reviewed as appropriate following the formal procurement process.

Table 17. Assumption of synchronous condenser timing for each portfolio (date of first unit commissioned)

Portfolio option	Timing assumed for first synchronous condenser *(plus 1.5-months for each additional required)*	Justification of timing
Portfolio option 1 and 2	March 2029	This is considered the earliest credible, yet optimistic, timing assuming fast progression through regulatory and procurement processes.
Portfolio option 3	February 2030	This is the estimated timing following a standard progression through regulatory and procurement processes.
Portfolio option 4	First five synchronous condensers from May 2028 Remaining synchronous condensers from February 2030	This portfolio option tests the benefits of accelerating five network (Transgrid) synchronous condensers, requiring procurement prior to the conclusion of the regulatory process (i.e. 'partial' acceleration). Since acceleration of the first five synchronous condensers has not been confirmed, this portfolio option is not currently considered credible (similar to PADR portfolio option 2).
Portfolio option 5	May 2028	This portfolio option tests the benefits of accelerating all ten network synchronous condensers (i.e. 'full' acceleration). Similar to portfolio option 4, this portfolio option is a hypothetical and is not currently considered credible.

March 2029 (for portfolio option 1 and 2) and February 2030 (for portfolio option 3) represents a range of credible timing of when the first synchronous condenser could be deployed, following normal regulatory and procurement processes. The range is due to uncertainty in factors external to Transgrid, including the regulatory approval process with the AER, the dispute process of the PACR and lead-times of synchronous condensers.

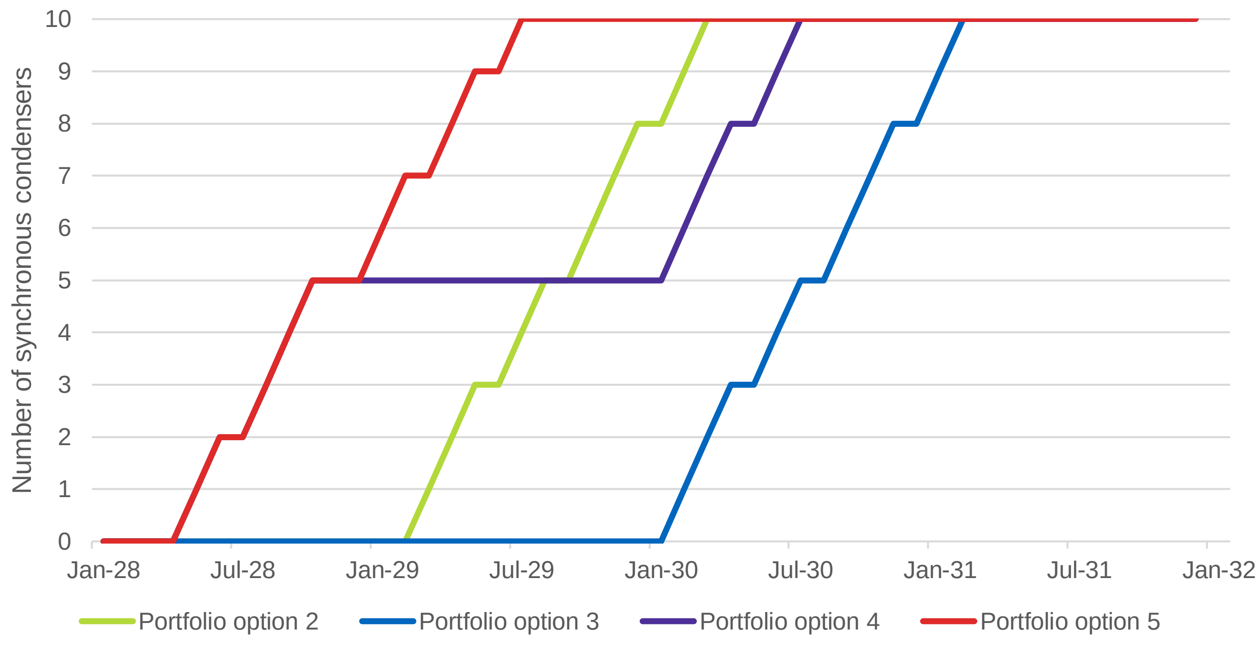
It was considered prudent to conduct the portfolio optimisation process using the earliest credible timing (March 2029) to reveal which synchronous condensers are needed earliest, as synchronous condensers are staggered and cannot be deployed simultaneously. This information was critical to identify the optimal location, amount and build-order of synchronous condensers, as was the objective for portfolio options 1 and 2.

However, to analyse the impact the timing of synchronous condenser deployments has upon the net market benefits of the enhanced portfolio, Transgrid has opted to test the timing of synchronous condenser availability from February 2030, which is considered more likely. This enables an assessment of the cost of later deployment through portfolio option 3 and the benefits of earlier than credible deployment through portfolio options 4 and 5.

The change in the first available synchronous condenser timing from March 2029 to February 2030 and the manual adjustments under portfolio options 3 to 5 are not expected to lead to a divergence of new-build solutions if re-optimised through PLEXOS, due to limited new build system strength solutions to meet the minimum level need in the early 2030s. The portfolio composition would only be expected to materially change if synchronous condensers are delayed beyond 2032/33 when grid-forming batteries can contribute to the minimum level. This was tested in the PADR between portfolio options 2 and 1 (PADR option numbering), the difference in timing did not affect the number of synchronous condensers required. As such, the manual adjustment methodology was considered appropriate.

The deployment schedule of network (Transgrid) synchronous condensers is shown in Figure 26. The effect of staggering subsequent synchronous condensers required in each year by 1.5-months can be seen clearly. The location and order of synchronous condensers is identical for each portfolio option.

Figure 26. Deployment schedule of network (Transgrid) synchronous condensers



8.1. Summary of portfolio composition for portfolio options 3 to 5

The composition of portfolio options 3 to 5 is shown in Table 18; note portfolio option 2 is also shown for comparison. As only a manual adjustment to the timing of network synchronous condensers occurred, all other new-build solutions are unchanged.

Table 18. Summary of the composition of portfolio options 2 – 5. Note all MW values are rounded to the nearest 50 MW

	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050MVA fault current), see note 1									
Portfolio 2	-	-	-	3	10	10	10	10	10
Portfolio 3	-	-	-	-	4	10	10	10	10
Portfolio 4	-	-	2	5	9	10	10	10	10
Portfolio 5	-	-	2	9	10	10	10	10	10
New England REZ synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)									
All portfolios	-	-	-	-	-	-	5	7	7
Hunter-Central Coast REZ system strength solutions									
All portfolios	-	-	Note 2	-	-	-	-	-	-
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) Cumulative capacity (MW)									
All portfolios	50	50	300	650	650	650	650	650	650
Grid-forming BESS Cumulative capacity (MW)									
All portfolios	-	1,350	3,250	3,650	4,150	4,800	4,800	4,950	8,150

Note 1: Synchronous condensers with a fault level contribution of 1,050 MVA have been assumed for this analysis. If synchronous condensers with a fault level contribution of <950MVA are selected through Transgrid's procurement process (calculated using unsaturated reactance), an additional one synchronous condenser is required in the Sydney West or Newcastle region, in 2030/31 under portfolio option 3, in 2029/30 under portfolio option 2 and 4, and in 2028/29 under portfolio option 5.

Note 2: Studies have identified four non-network synchronous condensers (275 MVA fault current contribution each) or 200 MW of grid-forming BESS are required to meet the efficient level requirement in the Hunter-Central Coast REZ, and the cost of each are within a margin of error. Transgrid has opted to identify the preferred system strength solution and proponent to meet the need in this REZ through the procurement process (which will be contracted as a non-network option).

8.2. Summary of risks of system strength gaps

In comparison to portfolio option 2, the later deployment of synchronous condensers in portfolio option 3 exacerbates the risks of gaps in system strength in 2028/29 and incurs additional risks of gaps in 2029/30 before sufficient synchronous condensers are installed. The difference in the risk of gaps is particularly apparent in the period between March 2029 and February 2030, being the assumed timings for first available synchronous condensers in options 2 and 3, respectively.

Portfolio options 4 and 5 close the risk of gaps forecast for 2028/29 and 2029/30. There are still risks of gaps remaining in 2027/28 before synchronous condensers can be deployed. There is no change in risk of forecast gaps between portfolio options 4 and 5 (though portfolio option 5 reduces the re-dispatch of synchronous machines in 2028/29 and 2029/30).

Table 19. Risk of gaps in system strength for portfolio options 2 - 5

	Portfolio option 2	Portfolio option 3	Portfolio option 4	Portfolio option 5
2025/26	No gaps	No gaps	No gaps	No gaps
2026/27	No gaps	No gaps	No gaps	No gaps
2027/28	Risk of gaps	Risk of gaps	Risk of gaps	Risk of gaps
2028/29	Risk of gaps	Risk of gaps	No Gaps	No gaps
2029/30	No gaps	Risk of gaps	No Gaps	No gaps
2030/31	No gaps	No gaps	No gaps	No gaps
2031/32	No gaps	No gaps	No gaps	No gaps
2032/33	No gaps	No gaps	No gaps	No gaps

Risks of gaps in the minimum level of system strength are projected to occur in portfolio option 3 – 5 for:

- up to 2% of time in 2027/28 across all three portfolio options;
- up to 1.5% of time in 2028/29 for portfolio options 3 at all nodes other than Armidale, and up to 10% of the time at Armidale if critical planned outages of transmission lines occur as modelled, to connect new transmission infrastructure and REZs; and
- up to 5% of time in 2029/30 under portfolio option 3 at all nodes other than Armidale, and gaps of over 20% of time at Armidale if critical planned outages of transmission lines occur as modelled.

Note that gaps observed during critical planned outages may be partially mitigated if outages can be co-ordinated with periods of high system strength.

8.3. Composition of portfolio option 3: Standard synchronous condensers timing

Portfolio option 3 is formed through a manual adjustment of portfolio option 2, modifying the assumed timing of the first available network synchronous condensers from March 2029 to February 2030, with all else held constant.

8.3.1. Synchronous condensers

Table 20 shows the location and timing of the synchronous condensers included in portfolio option 3. The quantum and location of synchronous condensers is the same as in portfolio option 2, with only the earliest timing of synchronous condensers delayed. This defers the entry of all ten network synchronous condensers by 11 months each. The timing of the New England REZ synchronous condensers is unaffected as they are not required until 2031/32.

Table 20. Synchronous condensers included in portfolio option 3

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Location	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**By 2044/45**
Armidale	-	-	1	1	1	1	1
Newcastle	-	-	1	2	2	2	2
Liddell	-	-	-	1	1	1	1
Eraring	-	-	-	1	1	1	1
Kemps Creek	-	-	1	2	2	2	2

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Wellington	-	-	1	1	1	1	1
Darlington Point	-	-	-	1	1	1	1
Dinawan	-	-	-	1	1	1	1
Total network (Transgrid)	**-**	**-**	**4**	**10**	**10**	**10**	**10**
New England REZ	-	-	-	-	5	7	7

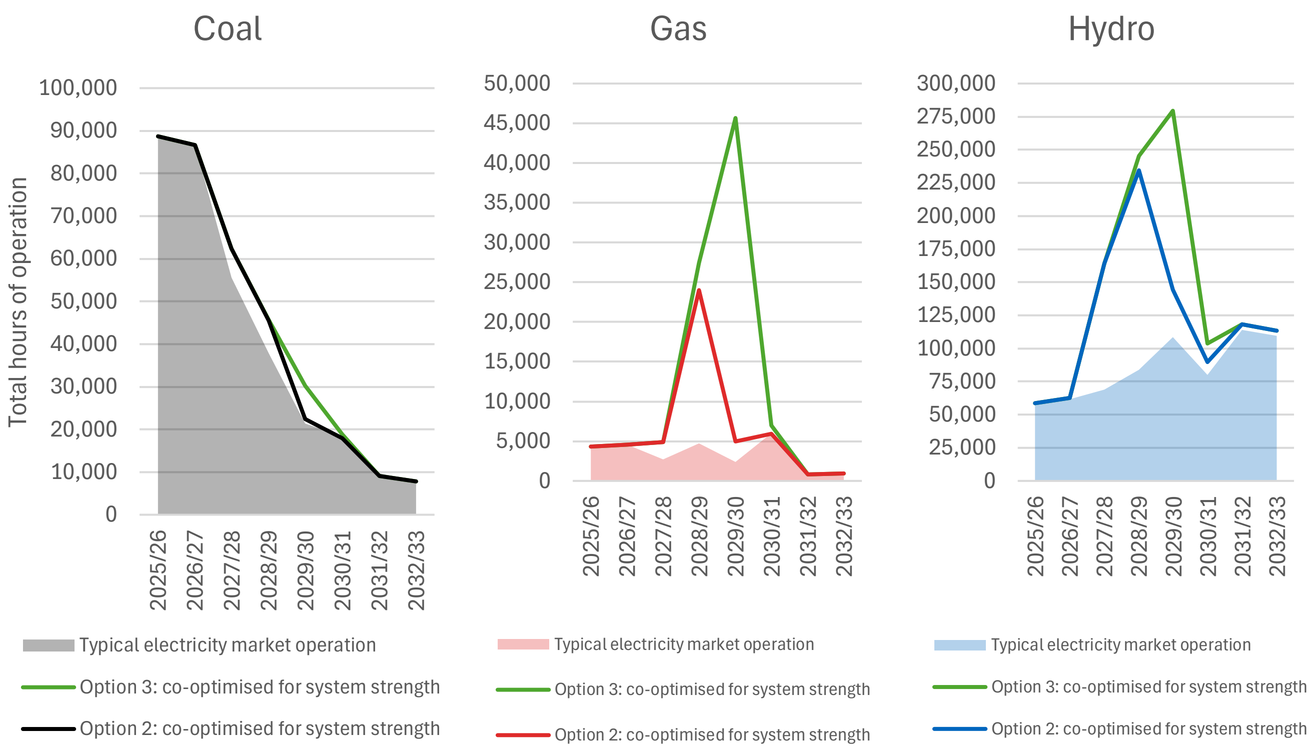
The total estimated cost of the network (Transgrid) synchronous condensers in present value terms (in 2023/24 dollars) is approximately $940 million in capital costs and $61 million in operating costs respectively, over the assessment period. In present value terms, these capital and operating costs are $83 million and $6 million lower than portfolio option 2, respectively, due to delayed procurement.

The cost of system strength solutions to remediate the New England and Hunter-Central Coast REZs is identical for portfolio options 2 – 5.

8.3.2. Re-dispatch of existing and committed generators

The later deployment of synchronous condensers puts additional reliance on existing and committed synchronous generator re-dispatch to meet system strength requirements. This is particularly evident in 2029/30 as shown in Figure 27.

Figure 27. Re-dispatch occurring in portfolio option 3, compared to that of portfolio option 2



Although gas constraints are applied (see Appendix E.6), there is significant uncertainty if there is enough gas to supply this level of re-dispatch seen in 2029/30, as it increases from approximately 5,000 additional hours of operation in portfolio option 2 to over 45,000 additional hours in portfolio option 3.

All portfolio options (including 3 – 5) rely on some hydro re-dispatch to meet the need in the first two years (no coal or gas re-dispatch).

8.4. Composition of portfolio option 4: *Partial acceleration of synchronous condensers*

Portfolio option 4 assumes five synchronous condensers can be accelerated earlier than the credible timing under the standard regulatory process, consistent with the approach taken in portfolio option 2 of the PADR. The first five synchronous condensers are assumed to be staggered from May 2028, in 1.5-month intervals. The remaining synchronous condensers are staggered from a first available date of February 2030.

8.4.1. Synchronous condensers

The location and timing of the synchronous condensers included in portfolio option 4 is shown in Table 21. The amount and location of synchronous condensers in portfolio option 4 is the same as in portfolio option 2 and 3, with only their deployment timing affected.

Table 21. Synchronous condensers for portfolio option 4

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Location	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**By 2044/45**
Armidale	-	1	1	1	1	1	1
Newcastle	1	1	2	2	2	2	2
Liddell	-	-	-	1	1	1	1
Eraring	-	-	1	1	1	1	1
Kemps Creek	1	1	2	2	2	2	2
Wellington	-	1	1	1	1	1	1
Darlington Point	-	1	1	1	1	1	1
Dinawan	-	-	1	1	1	1	1
Total network (Transgrid)	**2**	**5**	**9**	**10**	**10**	**10**	**10**
New England REZ	-	-	-	-	5	7	7

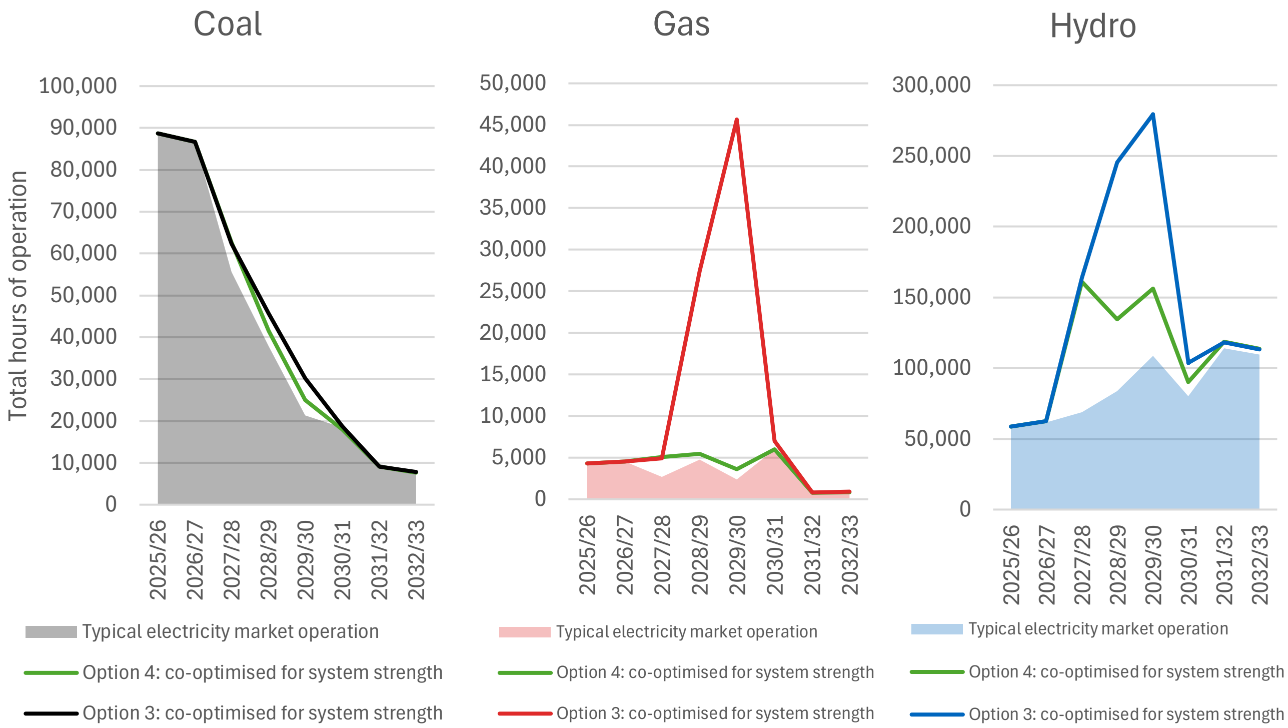
The total estimated cost of the network (Transgrid) synchronous condensers in present value terms (in discounted 2023/24 dollars) is approximately $1,045 million in capital costs and $69 million in operating costs, over the assessment period. In present value terms, these capital and operating costs are:

- $22 million in capital costs and $2 million in operating costs higher than portfolio option 2; and
- $105 million in capital costs and $8 million in operating costs higher than portfolio option 3.

8.4.2. Re-dispatch of existing and committed generators

The accelerated deployment of five synchronous condensers significantly reduces total re-dispatch hours compared to portfolio option 3. There is a reduction of more than 40,000 additional gas operating hours in 2029/30. Significant re-dispatch of hydro remains in 2027/28 before the entry of the five accelerated synchronous condensers.

Figure 28. Re-dispatch occurring in portfolio option 4, compared to portfolio option 3



8.5. Composition of portfolio option 5: Full acceleration of synchronous condensers

Portfolio option 5 assesses the benefits of full acceleration of all ten network (Transgrid) synchronous condensers.

8.5.1. Synchronous condensers

The location and timing of the synchronous condensers included in portfolio option 5 is shown in Table 22. The amount and location of synchronous condensers in portfolio option 5 is the same as in portfolio option 2, 3 and 4, with only their deployment timing affected.

Table 22. Synchronous condensers for portfolio option 5

Synchronous condensers – cumulative number of units (each providing 1,050 MVA fault current)							
Location	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Armidale	-	1	1	1	1	1	1
Newcastle	1	2	2	2	2	2	2

Eraring	-	1	1	1	1	1	1
Liddell	-	-	1	1	1	1	1
Kemps Creek	1	2	2	2	2	2	2
Wellington	-	1	1	1	1	1	1
Darlington Point	-	1	1	1	1	1	1
Dinawan	-	1	1	1	1	1	1
Total network (Transgrid)	**2**	**9**	**10**	**10**	**10**	**10**	**10**
New England REZ	-	-	-	-	5	7	7

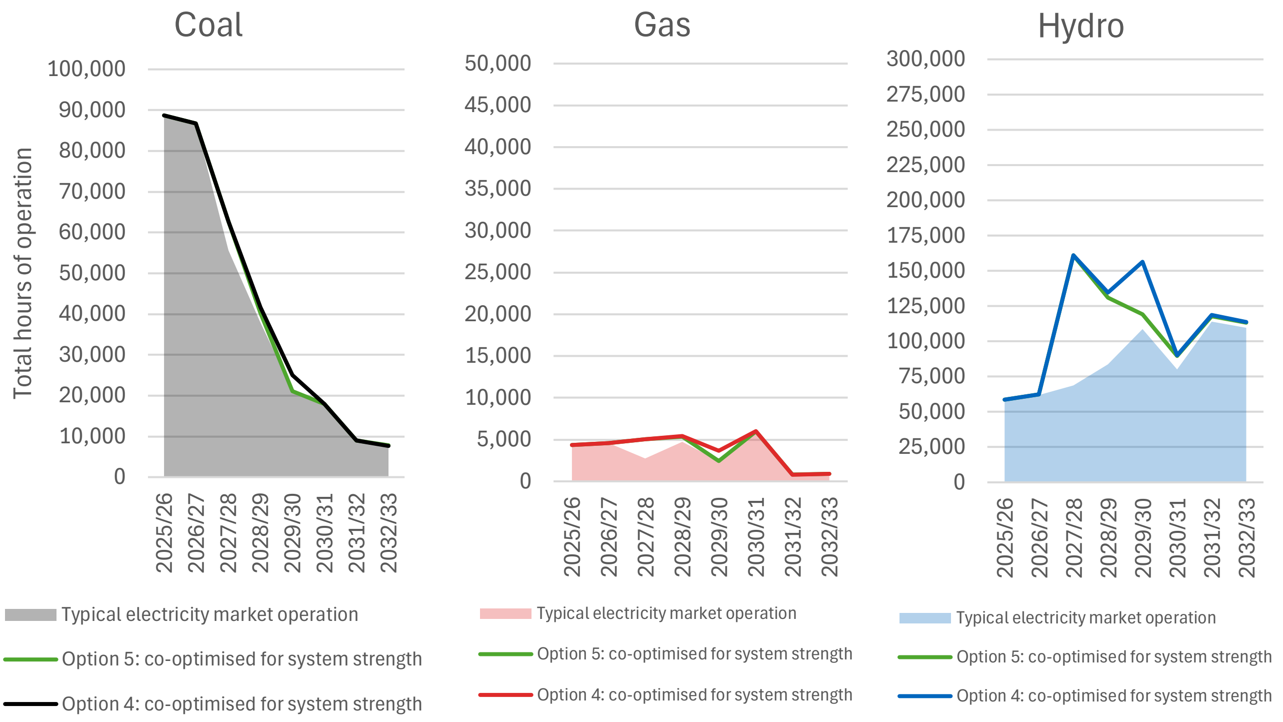
The total estimated cost of the network (Transgrid) synchronous condensers in present value terms (in 2023/24 dollars) is approximately $1,094 million in capital costs and $73 million in operating costs, over the assessment period. In present value terms, these capital and operating costs are:

- $71 million in capital costs and $6 million in operating costs higher than portfolio option 2; and
- $154 million in capital costs and $11 million in operating costs higher than portfolio option 3.

8.5.2. Re-dispatch of existing and committed generators

The accelerated deployment of all ten network synchronous condensers further reduces total re-dispatch hours in 2028/29 compared to portfolio option 4, where only five synchronous condensers are accelerated. This predominately impacts hydro re-dispatch hours in 2029/30, as shown in Figure 29.

Figure 29. Re-dispatch occurring in portfolio option 5, compared to portfolio option 4



8.6. Net market benefits for portfolio options 3, 4 and 5

The later entry of synchronous condensers in portfolio option 3 (i.e. from February 2030) results in a present value $2.2 billion reduction in net market benefits against portfolio option 2 (in 2023/24 dollars), which applies earlier synchronous condenser timing (i.e. from March 2029). The substantial reduction in net market benefits is primarily driven by significantly larger risks of gaps in system strength which occur due to the lack of available alternative system strength solutions, in absence of synchronous condensers.

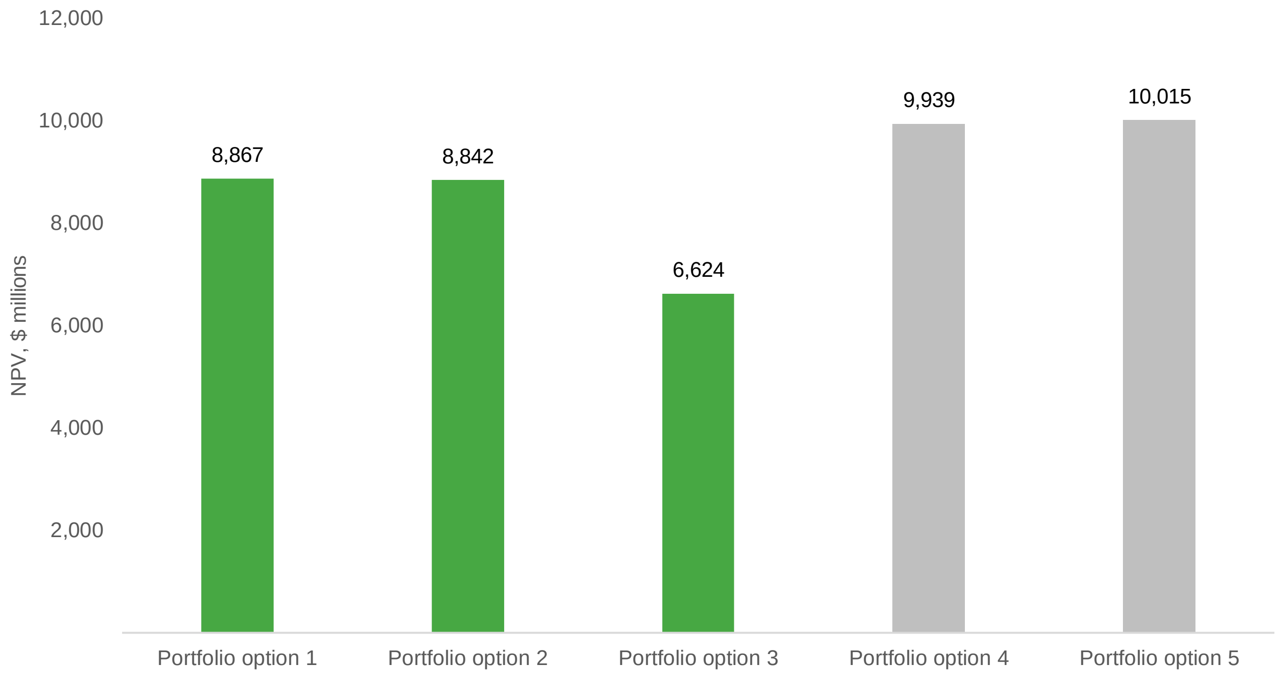
Portfolio option 4 and portfolio option 5, with partial and full acceleration of synchronous condensers respectively, deliver significant additional market benefits, as seen by:

- a $3.3 billion increase in net market benefits when the procurement of five network synchronous condensers is accelerated (portfolio option 4 compared to 3), or $1.1 billion compared to portfolio option 2; and
- a $3.4 billion increase in net market benefits when the procurement of ten network synchronous condensers is accelerated (portfolio option 5 compared to 3), or $1.2 billion compared to portfolio option 2.

The substantial benefits these accelerated portfolio options bring is primarily attributed to avoiding risks of system strength gaps compared to portfolio options 2 and 3 (leading to involuntary load shedding), lower generator fuel and operating costs (from lower re-dispatch of coal, gas and hydro) and reduction in greenhouse gas costs. The benefits of acceleration significantly outweigh the higher net present capital and operating costs of synchronous condensers due to earlier expenditure.

The headline NPV results for portfolio options 3 to 5, with comparison to portfolio option 1 and 2, are summarised in Figure 30. Green indicates a portfolio option which is currently credible, while grey indicates a portfolio option that is not yet credible. All portfolio options are found to generate substantial estimated net benefits over the assessment period compared to the base case.

Figure 30. Headline NPV results for portfolio option 1 to 5. Green indicates a portfolio option is currently credible; grey indicates a portfolio option that is not yet credible, but would deliver additional market benefits to consumers



The net market benefit analysis for portfolio option 3, 4 and 5 is discussed in more detail below.

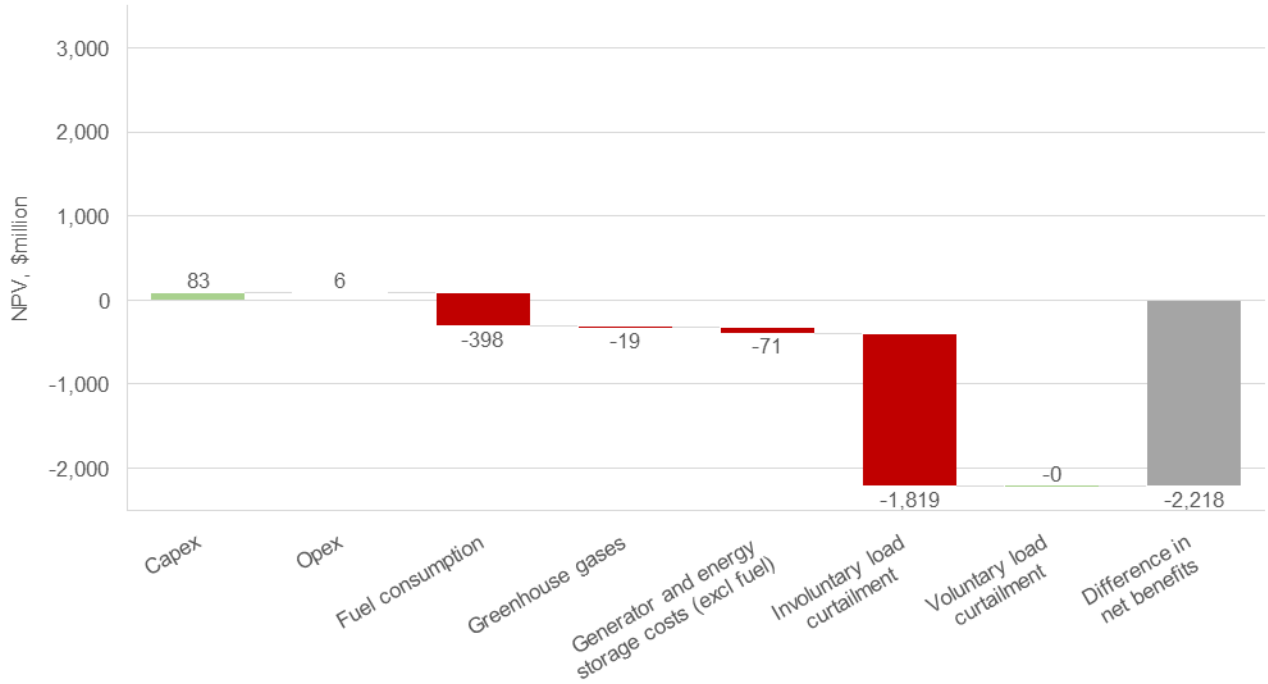
8.6.1. Portfolio option 3

Portfolio option 3, with earliest synchronous condenser delivery from February 2030, has a significant reduction in net market benefits with respect to portfolio option 2 (where synchronous condensers are delivered from March 2029). This is predominately driven by ongoing risks of gaps in system strength which cannot be met by alternative system strength solutions prior to the delivery of synchronous condensers.

There is also an increased reliance on redispatch of existing and committed synchronous generators for provision of system strength in the absence of earlier synchronous condensers. This drives an increase in fuel costs and generator costs which reduces the net market benefits of portfolio option 3 further.

The composition of net market benefits for portfolio option 3 (i.e. synchronous condensers from February 2030) is compared against portfolio option 2 (i.e. synchronous condensers from March 2029) in Figure 31.

Figure 31. Key changes in the composition of the estimated net market benefits for portfolio option 3, compared to portfolio option 2 (NPV, $millions)



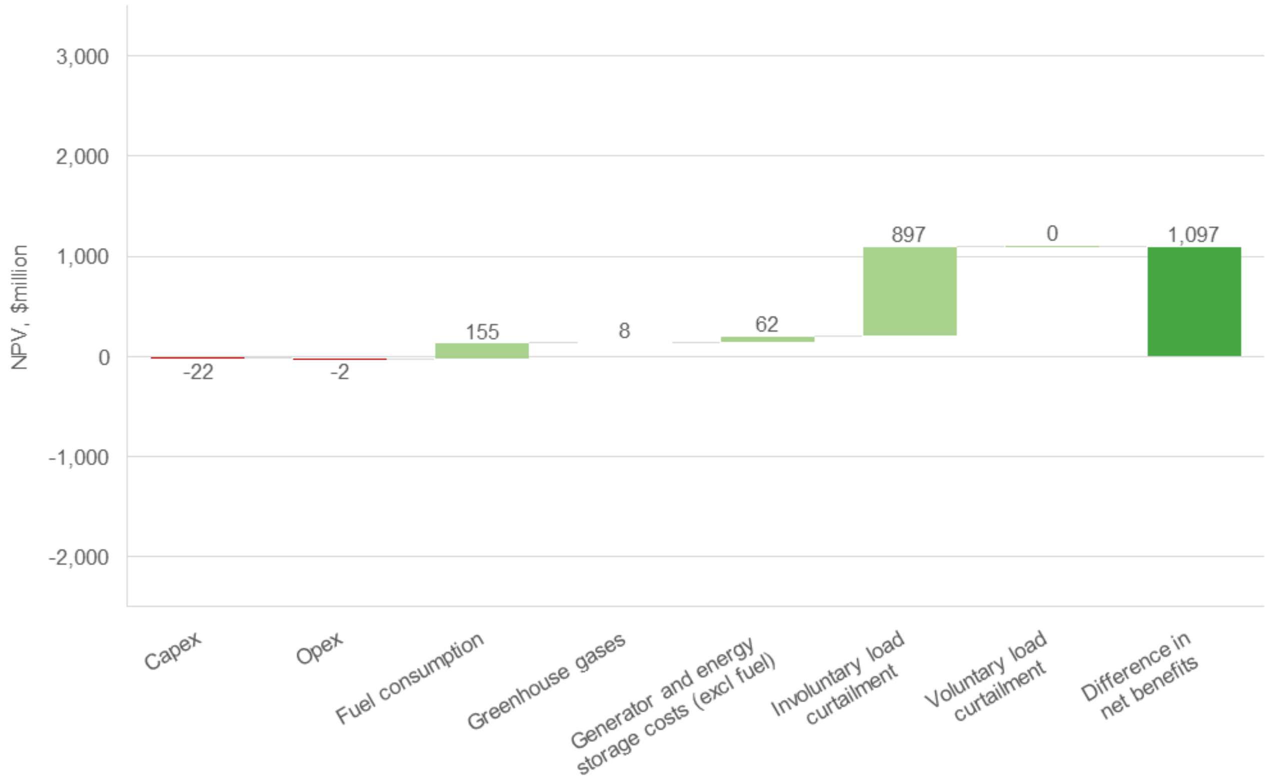
8.6.2. Portfolio option 4

In portfolio option 4, five synchronous condensers are assumed to be accelerated and delivered from May 2028, with the remaining delivered from February 2030. Earlier synchronous condenser deployment is shown to have substantial net market benefits due to the reduction in risks of system strength gaps which are forecast in 2028/29 under portfolio option 2 and both 2028/29 and 2029/30 under portfolio option 3.

This section compares portfolio option 4 to both portfolio option 2 (March 2029 synchronous condenser timing) and portfolio option 3 (February 2030 synchronous condenser timing). This is intended to provide a range of forecasted net market benefits depending on the actual earliest synchronous condenser delivery date under the standard regulatory process (expected to be between March 2029 and February 2030).

The composition of estimated net market benefits for portfolio option 4 is compared against portfolio option 2 in Figure 32, with an additional $1.1 billion in net market benefits seen. This figure is a lower bound of the expected benefits of partial acceleration as the earliest delivery timing of synchronous condensers in portfolio option 2 is considered the earliest credible timing for synchronous condensers under the standard regulatory framework.

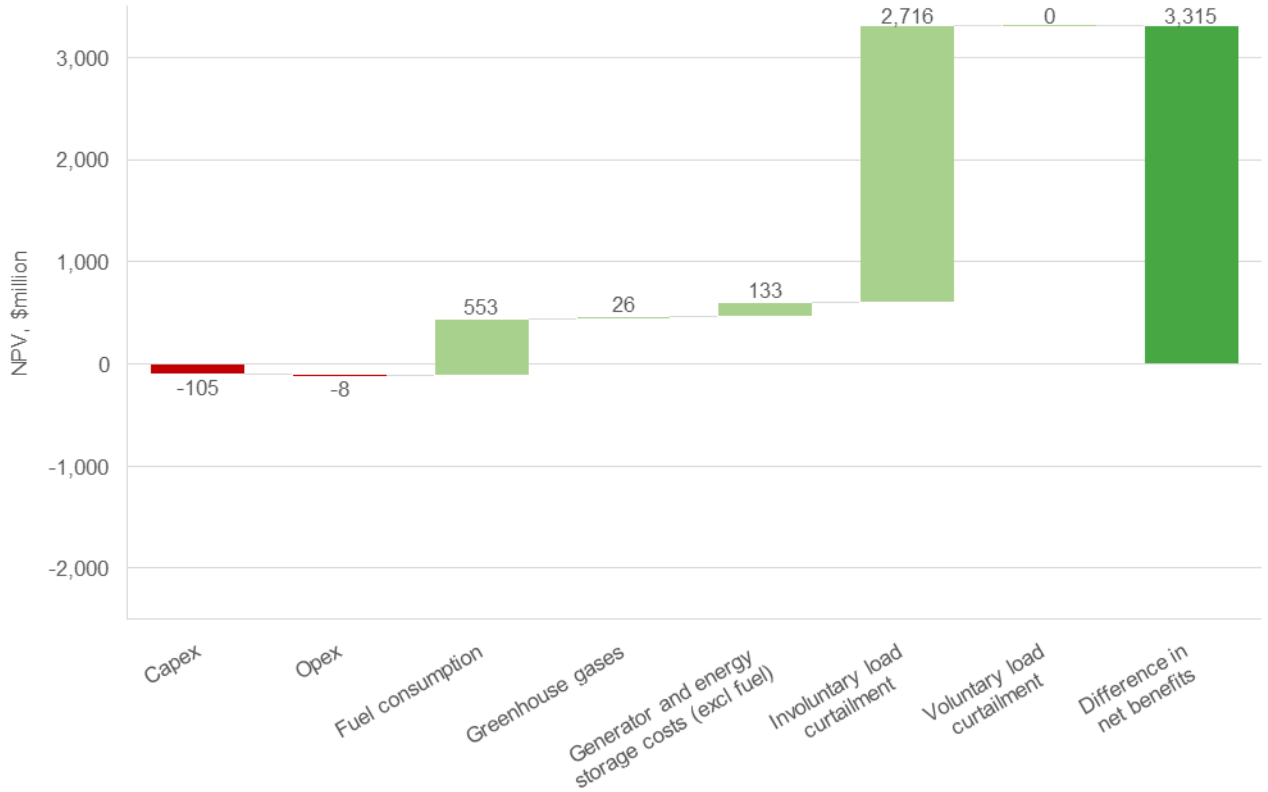
Figure 32. Key changes in the composition of the estimated net market benefits for portfolio option 4, compared to portfolio option 2 (NPV, $millions)



The benefits of partial acceleration are attributed primarily to reduced involuntary load curtailment (due to unfilled gaps in system strength) and avoided fuel costs associated with re-dispatch of thermal generation.

The upper bound to the expected benefits of partial acceleration is captured through a comparison with portfolio option 3, where the earliest delivery of synchronous condensers is deferred to February 2030. The breakdown of net market benefits of portfolio option 4 compared to portfolio option 3 is shown in Figure 33. Partial acceleration of synchronous condensers results in an increase in net market benefits of $3.3 billion with respect to portfolio option 3.

Figure 33. Key changes in the composition of the estimated net market benefits for portfolio option 4, compared to portfolio option 3 (NPV, $millions)

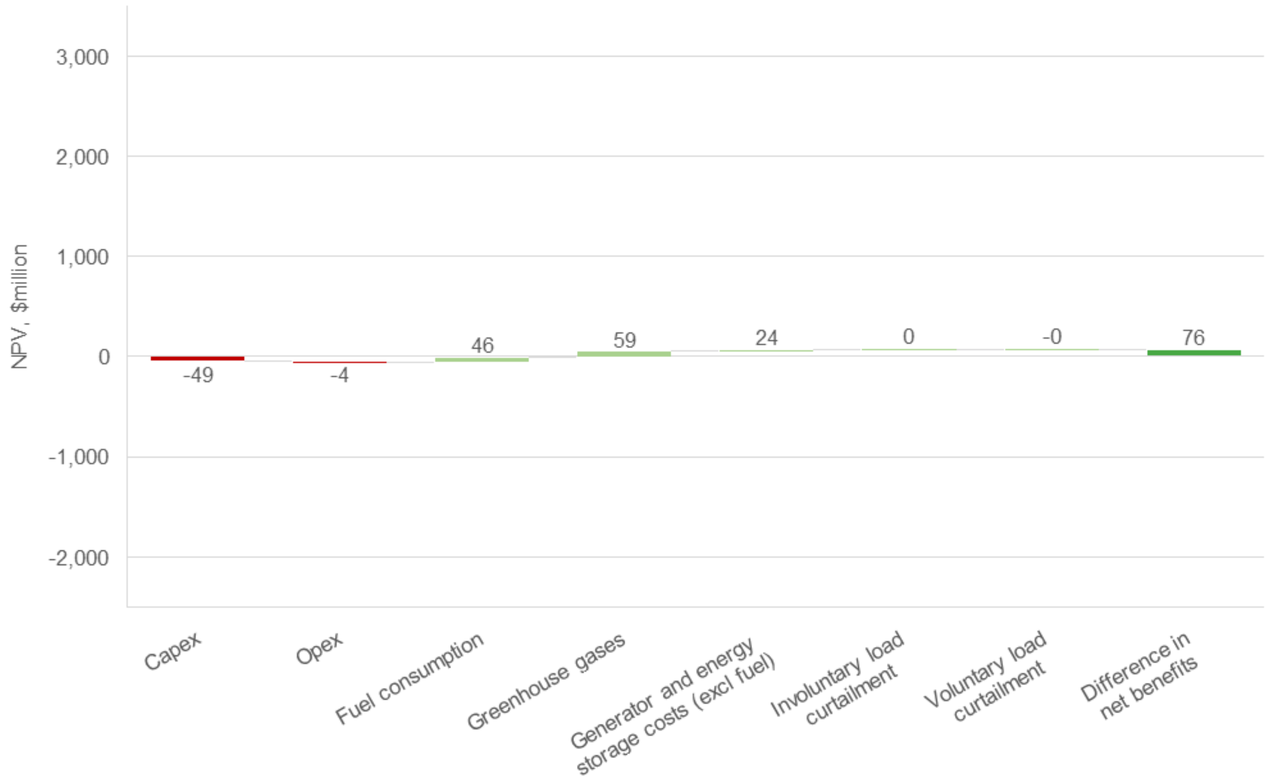


Portfolio option 4 demonstrates that the benefits of acceleration of five synchronous condensers are expected to be substantial, regardless of the earliest delivery date under the regulatory process with the net market benefits ranging from $1.1 billion to $3.3 billion.

8.6.3. Portfolio option 5

The net market benefits for portfolio option 5 (full acceleration of ten Transgrid synchronous condensers from May 2028) is compared against portfolio option 4 (partial acceleration of synchronous condensers from May 2028 with the remainder from Feb 2030) in Figure 34. Portfolio option 5 has $76 million higher net market benefits driven by a reduction fuel costs, greenhouse gas emissions and generator and storage costs. There is no difference in involuntary load curtailment as the risk of system strength gaps is the same under both portfolio options.

Figure 34. Key changes in the composition of the estimated net market benefits for portfolio option 5, compared to portfolio option 4 (NPV, $millions)



8.7. Acceleration of synchronous condensers is preferred, if proven credible

Portfolio options 4 and 5 incorporate partial and full acceleration of synchronous condensers respectively. The benefits of both portfolio options are significantly higher than portfolio option 2 and 3, which is a strong justification for the urgent procurement of network synchronous condensers.

Portfolio option 5 (full acceleration) has $76 million higher net market benefits than partial acceleration (portfolio option 4). Transgrid expects the actual difference in benefits will be even higher than this, similar to the comparison between the 'enhanced portfolio' and the 'basic portfolio'. This is due to the added resilience it provides to the NSW power system to plausible events which increase the system strength need (including resilience to high impact, low probability events).

Examples of plausible events that could occur in the future which would lead to higher re-dispatch costs, curtailment of renewables or gaps in system strength include delays to transmission projects, earlier or larger than expected IBR growth, early or unexpected closure of coal generators, extended coal generator outages and low rainfall years.

Two case studies of plausible events are presented below to indicate the potential for portfolio option 5 to demonstrate the higher net market benefits stemming from added resilience, including:

- If the timing of South West REZ IBR build-out is consistent with advice from EnergyCo, portfolio option 5 has an additional estimated $20 million in net benefits relative to portfolio option 4; and

- Accelerated procurement of synchronous condensers to help manage the risk of delays to transmission infrastructure. For example, if the Hunter Transmission Project is delayed by two years, portfolio option 5 has an additional $30 million in net benefits relative to portfolio option 4.

In comparison to portfolio option 4 (partial acceleration), we expect further benefits of full acceleration can be drawn from greater efficiencies during the procurement phase for synchronous condensers. By procuring synchronous condensers close together, Transgrid can build efficiencies from one tender to another and minimise both the cost and risk for consumers. If there is a significant gap between synchronous condenser procurement rounds, then previous information becomes out-dated and the process may need to be repeated in full.

Providing resilience to future uncertainties is in line with the AEMC Reliability Panel's view[62] on the asymmetric risk of early or late-investment in system strength (or over and under-investment), as quoted: *"the risks of over- and under-investment are asymmetric. The risk of over-investment in security services, or investment earlier than needed, comes with much lower costs than under-investment or investment that is too late. Under-investment could lead to periods when the NEM cannot be securely operated."*

System strength solutions to meet the minimum level are critical to unlocking the ability of the NSW power system to operate safely and securely without relying on the operation of coal generators. Acceleration of synchronous condensers would enable earlier achievement of 100% instantaneous renewables in NSW.

Acceleration of synchronous condensers is also expected to provide additional benefits by reducing the volume of re-dispatch required and increasing competition between non-network synchronous machines, particularly as coal generators progressively retire or move to operate more flexibly. This is significant as non-network contract prices offered are likely to be higher than the underlying economic cost of the service as modelled in the PACR (as per RIT-T guidelines).

Portfolio option 2 is currently the preferred credible portfolio option in this PACR, since portfolio options 4 and 5 are not currently credible. Portfolio option 2 would be replaced as the preferred option by either portfolio option 4 or 5, depending on the extent accelerated procurement of synchronous condensers became credible.

In recognition of the urgency of system strength requirements, Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders to enable the regulatory and procurement process to progress as quickly as possible. Following publication of the PACR, Transgrid will continue this work to deliver Transgrid synchronous condensers as soon as possible, with the goal to reduce power system security risks and maximise net market benefits.

[62] AEMC Reliability Panel, 23 April 2025, Letter to AEMO: Reliability Panel comments on AEMO's Transition Plan for System Security and AEMC, 2021, Final Rule: Efficient management of system strength on the power system

Two case studies demonstrate plausible events which, if realised, would lead to additional net benefits of portfolio option 5.

Case study 1: timing of IBR in the South West REZ based on EnergyCo advice

In response to the consultation period for the PADR, EnergyCo provided a submission which suggested this RIT-T should incorporate a higher IBR forecast aligned to the capacity of EnergyCo's South West REZ Access Rights scheme. Subsequently, EnergyCo advised of successful access right proponents and the advised timing of each project. These projects are not considered anticipated/committed and therefore are not included in the base case PACR modelling. However, Transgrid has opted to undertake a sensitivity to assess the performance of the portfolio options to the higher IBR forecast (full sensitivity presented in Section 9.1.3).

This sensitivity indicated the earlier and higher forecast of IBR (as advised by EnergyCo) could not be fully supported by portfolio options 1 – 4, which may lead to constraints on renewable generation in 2028/29. Under portfolio option 5, the earlier deployment schedule can partially close this gap substantiating an additional $20 million in net market benefits relative to portfolio option 4 (which is driven by lower aggregate fuel costs and emissions in the NEM from not having to curtail renewable generation compared to the base case). This is due to the assumed timing that the Dinawan synchronous condenser can be commissioned by (in 2028/29 in portfolio option 5, rather than 2029/30 in portfolio option 4).

Case study 2: Later delivery of major transmission project

Bringing forward all ten synchronous condensers (portfolio option 5) can mitigate system strengths risks exacerbated by delays to major transmission projects. It is well understood these projects face challenges and uncertainties in project timelines. This is accounted for in AEMO's Electricity Statement of Opportunities (ESOO) Reliability Forecasts which assume 'anticipated' transmission projects are included one year after the commissioning dates provided by the developer.[63]

Transgrid has assessed the impacts of a potential late delivery of major transmission projects including HumeLink, the Hunter Transmission Project and VNI West. Hunter Transmission Project was selected for this case study as it materially impacts the contribution of system strength solutions to the Sydney West and Newcastle nodes, which have the greatest need for new system strength.[64] Transgrid assessed the increase in net market benefits for portfolio option 5 relative to portfolio option 4, under a scenario where Hunter Transmission Project is delivered two years later.

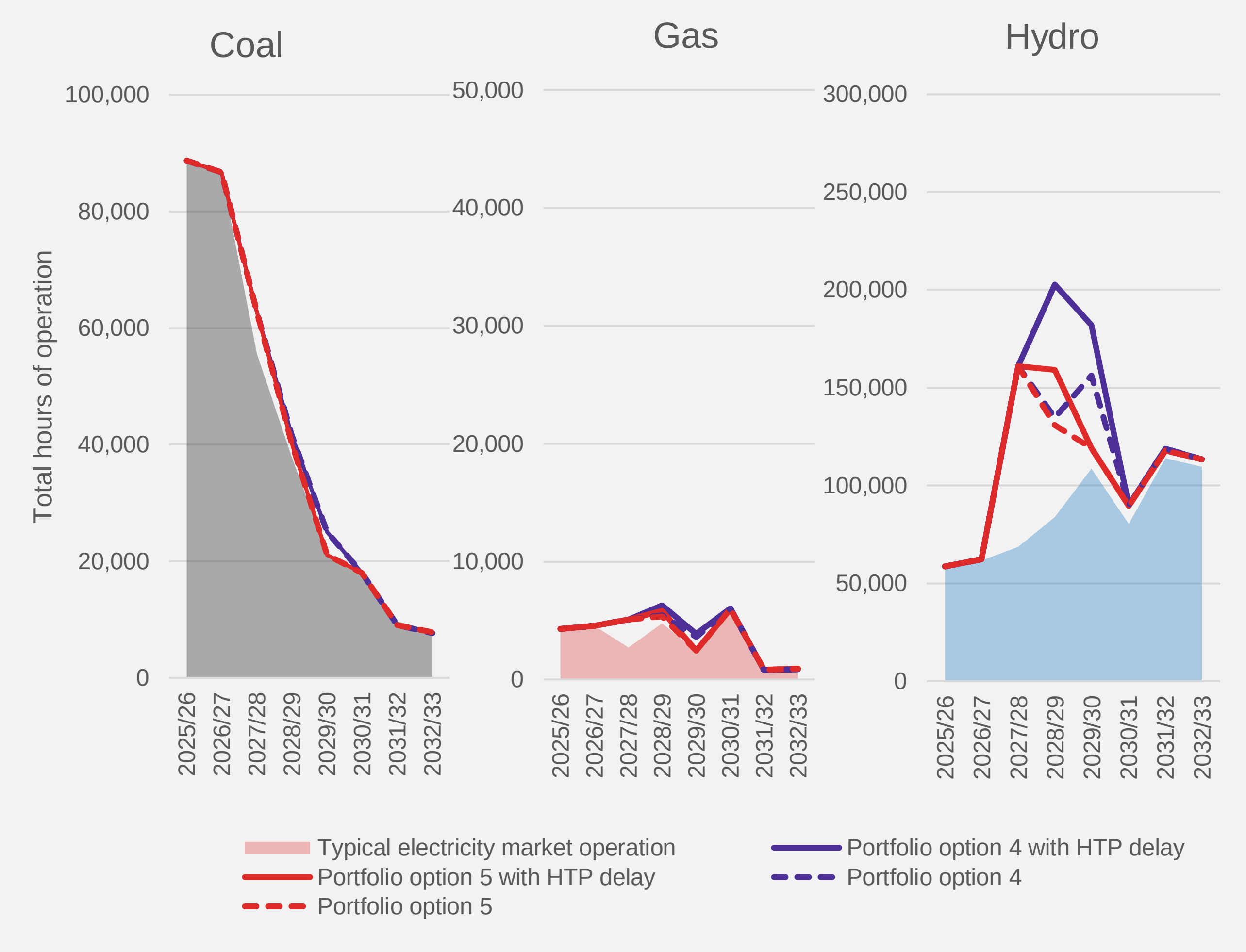
[63] AEMO, 2023, ESOO and Reliability Forecast Methodology Document

[64] Transgrid assessed that the system strength impact of a delay to HumeLink would be relatively minor (while it reduces the impedance of the network between the Snowy Mountain region and Bannaby, it does not improve the system strength 'bottleneck' between Bannaby and Sydney). A delay to the VNI West project would have a more significant impact on the provision of system strength support to Dinawan (both from Victoria via the new interconnector and from NSW via the 500kV Dinawan to Gugaa transmission line). However, a delay to VNI West wasn't selected for this case study since reduced system strength support at Dinawan would have an 'efficient' level impact only, whereas under a delay to the Hunter Transmission Project, the impacts would be a more material reduction to the minimum level of system strength surrounding Sydney West and Newcastle.

Results indicate that to compensate for the reduction in fault level at Sydney West and Newcastle caused by the delay, over 60,000 additional re-dispatch hours of hydro and over 600 re-dispatch hours of gas is required over the two years (Figure 35).

As such, an additional $30 million in net market benefits is expected in this case study under portfolio option 5, compared to portfolio option 4, associated with avoided fuel costs and emissions (i.e. lower re-dispatch of coal, gas and hydro).

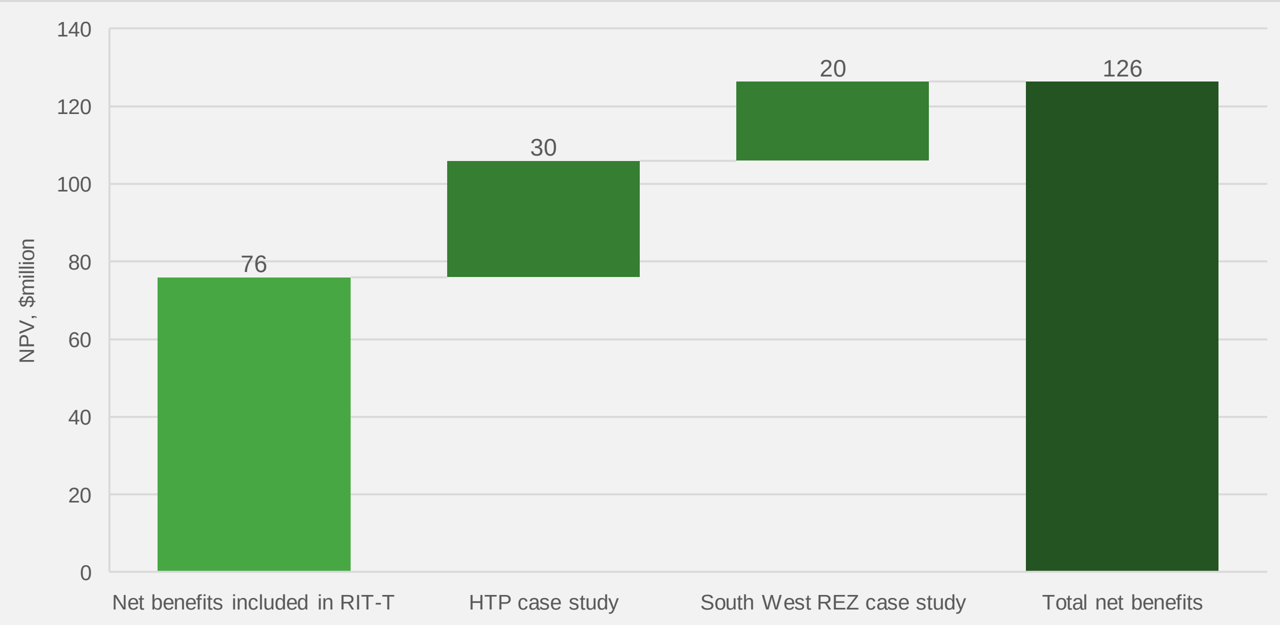
Figure 35. Re-dispatch for Hunter Transmission Project delay case study



Impact of both case studies on net benefits

Figure 36 presents the difference in net benefits of portfolio option 5 to portfolio option 4, when both case studies are included. Analysis identifies that portfolio option 5 would have an additional $126 million estimated net benefits compared to portfolio option 4.

Figure 36. Difference in net benefits of portfolio option 5 (against portfolio option 4), when the Hunter Transmission Project (HTP) delay case study and the earlier South West REZ case study are included



9. Sensitivity analysis and re-opening triggers for material changes in circumstance

Chapter Summary

Transgrid has conducted sensitivity analysis to test how changes in key assumptions underpinning this RIT-T would affect its findings. Three sensitivities were undertaken to assess changes to the portfolio composition, including:

- grid-forming BESS being able to provide more stable voltage waveform support than Transgrid currently expects;
- synchronous condenser costs being higher than forecasted (approximately 30% higher); and
- a change in forecast IBR in the South West REZ based on EnergyCo's Access Rights tender.

The results of these studies indicate only the selection of synchronous condensers for the New England REZ is sensitive to the performance of grid-forming BESS and synchronous condenser costs. There is no change to the need or timing of network (Transgrid) synchronous condensers under either sensitivity. Procurement of system strength solutions for New England REZ is not required to commence until 2027/28, at which time Transgrid will assess the party remediating the REZ and whether either of the drivers of these sensitivities have materialised (and will trigger a material change in circumstance if so).

The higher and earlier IBR forecast in the South West REZ Access Rights sensitivity leads to the requirement for additional system strength support from grid-forming BESS. Due to the earlier timing of IBR forecasts in this sensitivity, risks of gaps in the efficient level of system strength will materialise prior to the delivery of a synchronous condenser at Dinawan. The risk of these gaps is partially mitigated under portfolio option 5, due to the accelerated procurement of the Dinawan synchronous condenser.

Transgrid has also assessed the robustness of the ranking of portfolios under the NPV assessment to varying input assumptions, including changes to the Value of Emissions Reduction (VER), Value of Customer Reliability (VCR), capital cost and discount rates.

Transgrid has conducted sensitivity analysis to test how changes in the assumptions underpinning this RIT-T affect its findings. This analysis can be split into two categories:

- Sensitivity analysis to test changes to the portfolio composition; and
- Sensitivity analysis to test changes in the net market benefits.

9.1. Portfolio composition sensitivity analysis

Transgrid conducted three sensitivities within the portfolio formation process, by changing one key assumption each time and using the PLEXOS portfolio optimisation to form new portfolios. The three sensitivities tested are:

- grid-forming BESS can provide more stable voltage waveform support than Transgrid currently expects;
- synchronous condenser costs are higher than forecasted (approximately 30% higher); and

- a change in forecast IBR in the South West REZ based on EnergyCo's Access Rights tender. Note, this sensitivity was undertaken through PSCAD™.

In the PADR, we suggested undertaking additional sensitivity analysis to understand the impact of possible variations to the assumed retirement date of NSW coal generators. The PADR Supplementary Report investigated the effect of the extension to the retirement of the Eraring Power Station on the optimal portfolio, which deferred the need for additional synchronous condensers. Additional delayed coal retirement sensitivities may show a similar effect, however the asymmetric risk of under-procurement of system strength (i.e. if coal generators retire as expected under the Step Change scenario without sufficient deployment of synchronous condensers to provide system strength) is considered materially higher than the risk corresponding with earlier than required procurement (i.e. where synchronous condensers are installed prior to coal retirement dates).

The outcomes for the grid-forming BESS and higher synchronous condenser costs sensitivities are compared to portfolio option 1. This is because the portfolios identified by the sensitivities follow the PLEXOS portfolio optimisation process, rather than portfolio option 2 methodology which includes an additional manual adjustment to the timing and location of one synchronous condenser from portfolio option 1. The insights from these sensitivities would also be applicable to portfolio option 2.

9.1.1. Sensitivity of grid-forming BESS able to provide more stable voltage waveform support

This sensitivity tests how the optimal portfolio composition varies if grid-forming BESS can provide more stable voltage waveform support than is currently estimated by Transgrid's power system modelling.

For the PACR modelling, grid-forming BESS are assigned a 'boost factor' based on the inverter supplier selected. For projects without a selected supplier, a 'boost factor' of 2.6 is assumed (as described in Appendix B.3). For this sensitivity, all grid-forming BESS from 2031/32 are assumed to have the maximum boost factor of 4.1, approximately a 60% increase in performance. This reduces the cost of the solution on a per MVA basis. The year 2031/32 was selected since synchronous condensers required before this date will need to be procured immediately after the completion of this RIT-T and therefore this portion of the portfolio is fixed. The portfolio after 2031/32 does not require immediate procurement and may be adjusted based on latest information including updated performance assessments of grid-forming BESS.

A comparison of the results between portfolio option 1 and the grid-forming BESS boost sensitivity is presented in Table 23.

Table 23. Comparison of portfolio composition between core portfolio and grid-forming BESS Boost. Note all MW values are rounded to the nearest 50 MW.

	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)			
Portfolio option 1: Basic portfolio	9	9	9
GFM BESS Boost	9	9	9
New England REZ synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)			
Portfolio option 1: Basic portfolio	6	8	8
GFM BESS Boost	5	6	6
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) Cumulative capacity (MW)			

	2031/32	2032/33	By 2044/45
Portfolio option 1: Basic portfolio	650	650	650
GFM BESS Boost	650	650	650
Grid-forming BESS Cumulative capacity (MW)			
Portfolio option 1: Basic portfolio	4,800	4,950	8,150
GFM BESS Boost	4,800	4,950	7,850

Results of this sensitivity show a reduction in synchronous condensers required for the New England REZ from 6 to 5 in 2031/32 and from 8 to 6 in 2032/33. There was no change to the amount of grid-forming BESS to be procured by 2032/33. This indicates that although the contribution from grid-forming BESS was higher, synchronous condensers were still the most cost-and-benefits-effective solution for providing system strength. There was a relatively small decrease in grid-forming BESS required by 2044/45 (i.e. 300 MW), which represents a reduction in the total amount of new grid-forming BESS required to meet the same need if grid-forming BESS are performing better than expected. There was no material change in re-dispatch between the two portfolio options.

This sensitivity indicates higher performance of grid-forming BESS could reduce reliance upon synchronous condensers from 2031/32 which are identified for remediation of the New England REZ. We have included a material change in circumstances to this effect, discussed in Section 9.3.

Stronger performance of grid-forming BESS does not displace the need for network (Transgrid) synchronous condensers, as these synchronous condensers are required to mitigate system strength gaps to the minimum level requirements between 2028/29 and 2030/31, which cannot be met by grid-forming BESS.

9.1.2. Sensitivity applying higher than forecasted synchronous condenser costs

This sensitivity tests how the optimal portfolio changes if synchronous condenser costs are higher than forecasted. Transgrid developed costs for synchronous condenser projects through engagement with synchronous condenser suppliers and by undertaking feasibility studies of selected locations.

For this sensitivity, we re-optimised portfolio option 1 assuming approximately 30% higher cost of synchronous condensers, with all else being equal. The composition of portfolio option 1 and the higher cost sensitivity is displayed in Table 24 for comparison.

Table 24. Portfolio composition of portfolio option 1 and higher synchronous condenser cost sensitivity. Note MW values are rounded to the nearest 50 MW.

Portfolio option	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)							
Portfolio option 1: Basic portfolio	-	3	9	9	9	9	9
Higher cost sensitivity	-	3	9	9	9	9	9
New England REZ synchronous condensers Cumulative number of units (each providing 1,050MVA fault current)							

Portfolio option	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	By 2044/45
Portfolio option 1: Basic portfolio	-	-	-	-	6	8	8
Higher cost sensitivity	-	-	-	-	-	-	1
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)							
Portfolio option 1: Basic portfolio	650	650	650	650	650	650	650
Higher cost sensitivity	650	650	650	650	650	650	650
Grid-forming BESS – cumulative capacity (MW)							
Portfolio option 1: Basic portfolio	3,200	3,600	4,200	4,800	4,800	4,950	8,150
Higher cost sensitivity	3,200	3,600	4,250	4,850	4,850	6,100	8,600

The results show no change to the number of network (Transgrid) synchronous condensers required. This is because the entry of network synchronous condensers is predominantly driven by the minimum level requirements and synchronous condensers remain one of the only solutions.

At Dinawan, where a manual modelling assessment is applied (outlined in Section 6.6.1), the synchronous condenser remains more cost-effective per MVA than a grid-forming BESS (applying the entire cost as opposed to an anticipated/committed BESS where only the incremental cost to upgrade is considered). Therefore, higher synchronous condenser capex also does not change the optimal solution to meet the Dinawan system strength requirements.

The number of synchronous condensers for the New England REZ materially reduces from eight to zero by 2032/33 (and eight to one by 2034/35). In this sensitivity, the higher cost of synchronous condensers makes grid-forming BESS the most cost-effective solution to meet the efficient level requirements in New England REZ from 2031/32 and to meet the minimum level from 2032/33 (when they are assumed to be able to contribute to the minimum level). These synchronous condensers are displaced by an additional 1.15 GW of grid-forming BESS. We have included a material change in circumstances to this effect in Section 9.3.

There was no material change in re-dispatch hours between the two portfolio options.

A comparison of the CAPEX and OPEX costs between the core portfolio and the higher synchronous condenser cost sensitivity is shown in Table 25.

Table 25. Comparison of portfolio costs between basic portfolio and higher synchronous condenser cost sensitivity.

	Portfolio option 1	Higher cost sensitivity
Network (Transgrid) Synchronous condensers		
CAPEX	1,438	1,749
OPEX	141	171
Total	1,578	1,920

	Portfolio option 1	Higher cost sensitivity
New England REZ Synchronous condensers		
CAPEX	1,231	186
OPEX	102	13
Total	1,332	199
Hunter-Central Coast REZ System strength solutions		
CAPEX	181	181
OPEX	18	18
Total	199	199
Unit upgrades to allow synchronous condenser mode operation		
CAPEX	18	18
OPEX	0	0
Total	18	18
Grid-forming BESS		
CAPEX	2,644	3,770
OPEX	476	727
Total	3,120	4,498
Total cost		
CAPEX	5,511	5,904
OPEX	737	930
Total	6,248	6,835

The higher cost of synchronous condensers reduces the number of synchronous condensers materially for the New England REZ. However, the cost of the portfolio from the sensitivity is $587 million higher (undiscounted, 2023/24 dollars) than the basic portfolio, primarily due to the increase in synchronous condenser costs assumed in this sensitivity and the higher cost of grid-forming BESS to meet the need than synchronous condensers in portfolio option 1.

9.1.3. Variation to IBR in the South West REZ based on EnergyCo's Access Rights tender

For this sensitivity, Transgrid identified system strength solutions required to support stable voltage waveforms for a higher level of IBR, as per recently awarded Access Rights for South West REZ. The Access Rights Scheme awarded 3.56 GW of network transfer capacity across 4.3 GW of nameplate capacity IBR projects in May 2025. This is significantly higher than the IBR forecast used for this RIT-T (i.e. 2.6 GW).

The South West REZ sensitivity used information provided by EnergyCo to model the advised locations of Access Rights projects, capacities, likely equipment vendors and commissioning dates. These projects involved connections both along the Project Energy Connect transmission line and directly into the Dinawan substation, with extended third-party transmission lines from the project to the substation.

A comparison of the IBR forecast in South West REZ used for this RIT-T against the nameplate capacity of the projects holding Access Rights is shown in Figure 37.

Figure 37. Comparison of IBR in South West REZ forecasted for this RIT-T versus the South West REZ sensitivity

The basic and enhanced portfolio options (1 and 2) which use the IBR forecast for this RIT-T (2.6 GW), require one synchronous condenser from 2029/30 (discussed in Section 7.1). In this South West REZ sensitivity, the higher and earlier IBR level within the REZ drives a corresponding higher and an earlier efficient level requirement. The higher IBR capacity forecasted requires remediation above that provided by the single synchronous condenser. If an amount (specific value to remain confidential) of the forecast BESS under the South West REZ sensitivity are grid-forming, modelling in PSCAD™ shows this is sufficient to maintain stable voltage waveforms for the additional wind and solar projects (in combination with the one synchronous condenser).

The earlier build-out of IBR under the South West REZ sensitivity has risks of system strength gaps to the efficient level requirements, since synchronous condensers are first available from March 2029 in portfolio option 2. Portfolio option 5, with full accelerated synchronous condenser deployment, would enable the Dinawan synchronous condenser to be delivered approximately one year earlier (than portfolio option 2), partially mitigating the risk of gaps.

To prevent insufficient system strength from delaying the connection of Access Rights projects (or curtailment of connected Access Rights projects), Transgrid has opted to include a material change in circumstance for this RIT-T. This will be triggered if more than 2.6 GW of grid-following wind, solar or BESS in the region becomes anticipated or committed. If this trigger is met, and the IBR within the REZ includes committed or anticipated BESS, Transgrid will seek to procure system strength support from grid-forming BESS in the REZ. The amount of grid-forming BESS has not been publicly released to avoid the exercise of market power if Transgrid procures non-network solutions in the region. Transgrid will re-assess the amount of grid-forming BESS required using latest information at the time of the material change in circumstance.

If no committed or anticipated BESS projects materialise but the trigger is met, then Transgrid will re-assess the optimal system strength solutions to meet the need.

9.2. Net present value sensitivity analysis

Transgrid has assessed the robustness of the ranking of portfolios under the NPV assessment. This was undertaken through a range of sensitivity tests varying one input to test how robust the net present value output is to its input assumptions.

Specifically, Transgrid has undertaken sensitivity analysis for the RIT-T NPV assessment by testing:

- 25 percent higher and lower Value of Emissions Reduction (VER) values, (i.e., consistent with the MCE guidance);[65]
- 30 percent higher and lower Value of Customer Reliability (VCR) values (i.e., consistent with the AER's stated level of confidence);[66]
- 25 percent higher and lower synchronous condenser costs
- 25 percent higher and lower grid-forming BESS upgrade costs; and
- Higher (10.5%) and lower (4.18%) commercial discount rates (as discussed in Appendix F.10).

Transgrid has also estimated the 'boundary value' for key variables (e.g., assumed capital costs, discount rates) 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 9.3 of this PACR.

Appendix C presents the results of each of these sensitivities. The order of all portfolio options did not change across all sensitivities. A summary of the change in net market benefits for each sensitivity is shown in Table 26. The portfolio options are similarly affected by each sensitivity; this is expected given the similar composition of each portfolio option. As the timing of synchronous condensers is the key change between each portfolio option, the higher sensitivity of portfolio options to a change in commercial discount rates is observed.

Table 26. Summary of NPV sensitivity results

Sensitivity		Portfolio option 1	Portfolio option 2	Portfolio option 3	Portfolio option 4	Portfolio option 5
No change		0.0%	0.0%	0.0%	0.0%	0.0%
VER	Higher	6.8%	6.8%	9.0%	6.1%	6.2%
	Lower	-6.8%	-6.8%	-9.0%	-6.1%	-6.2%
VCR	Higher	6.2%	6.2%	0.0%	8.2%	8.1%
	Lower	-6.2%	-6.2%	0.0%	-8.2%	-8.1%
Synchronous condenser costs	Higher	-5.0%	-5.1%	-6.4%	-4.6%	-4.7%
	Lower	5.0%	5.1%	6.4%	4.6%	4.7%
Grid-forming BESS upgrade costs	Higher	-4.7%	-4.7%	-6.3%	-4.2%	-4.2%
	Lower	4.7%	4.7%	6.3%	4.2%	4.2%
Commercial discount rates	Higher (10.5%)	-37.1%	-37.3%	-43.5%	-34.9%	-34.9%

65 AEMC, MCE statement about the interim value of greenhouse gas emissions reduction
66 AER, September 2020, Widespread and long duration outages – values of customer reliability - Final conclusions

Sensitivity		Portfolio option 1	Portfolio option 2	Portfolio option 3	Portfolio option 4	Portfolio option 5
	Lower (4.18%)	47.9%	48.1%	58.1%	44.4%	44.4%

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 Table 27.

Table 27. Summary of boundary value analysis

Boundary values	VER	VCR	Higher synchronous condenser costs	BESS upgrade costs	Discount rate
Portfolio option 1	N/A	N/A	503.9%	530.8%	38.7%
Portfolio option 2	N/A	N/A	494.4%	529.3%	37.9%
Portfolio option 3	N/A	N/A	389.7%	396.5%	25.7%
Portfolio option 4	N/A	N/A	548.3%	595.0%	46.9%
Portfolio option 5	N/A	N/A	536.8%	599.5%	44.2%

9.3. Re-opening triggers for material change in circumstances

Under the rules relating to a material change in circumstances (MCC), Transgrid is required to set out re-opening triggers for this RIT-T. Each MCC trigger is to be informed (where possible) by analysis and boundary values. This can be used if the triggers are met, to enable the preferred solution to be adjusted without re-opening the RIT-T (if no other material changes have occurred).

Synchronous condensers form a critical component of all portfolio options to meet minimum level requirements as soon as possible. To minimise the risk of system strength gaps, Transgrid will undertake procurement of synchronous condensers as soon as possible upon completion of the PACR. Transgrid does not expect synchronous condensers required before 2031/32 to be sensitive to the identified triggers as:

- There is no alternative technology to meet the minimum level in time;
- The consequence of gaps to the minimum level is significant; and
- The long-lead time of synchronous condensers requires the solutions to be locked in as soon as possible to minimise system strength gaps.

The exception is if synchronous condensers can be deployed earlier than assumed in portfolio option 2, this should be pursued given the significant increase in net market benefits as modelled in this PACR.

Synchronous condensers required later in the assessment period (2031/32 onwards) do not require urgent procurement and there is flexibility if an MCC does occur. Transgrid will re-assess the preferred portfolio option before procurement of synchronous condensers required after 2031/32.

Consistent with these new requirements and drawing on the results of the sensitivity assessments outlined above (and published and consulted on in the PADR), Transgrid has considered the impact of changes in key underlying assumptions to identify re-opening triggers. Specifically, we consider the following re-opening triggers for this RIT-T:

- costs of synchronous condensers required for 2031/32 or after increase by significantly more than 30%;
- credible evidence emerges that a significant proportion of new connecting wind and solar projects are choosing to self-remediate their system strength impact;
- credible evidence emerges that a very high proportion of new connecting batteries are choosing to self-remediate their system strength impact by connecting with grid-forming capability;
- credible evidence emerges that the performance of grid-forming BESS to support stable voltage waveform is significantly higher than modelled;
- more than 2.6 GW of grid-following wind, solar or BESS capacity in the South West REZ elect to pay the system strength charge and reach anticipated or committed status;
- a material divergence between the economic cost, timing or scope of a significant non-network component of the portfolio options and the final contract price, schedule and scope obtained from proponents during the non-network procurement process; and
- EnergyCo informing Transgrid of their approach to system strength remediation for the New England REZ which materially changes the timing or scope of the need considered within this RIT-T.

Due to the dynamic drivers of system strength needs, Transgrid will use the outcome of this RIT-T in terms of non-network solutions to identify the type of solutions that we should contract with (as well as establishing broad requirements for amount and timing). However, during the ongoing procurement process for system strength, Transgrid will use the best information available to determine the specific location, number and timing of non-network solutions to contract with.

MCC related to non-network solutions is only expected to be triggered if the portfolio of non-network solutions varies from the PACR enough to change the optimal number of new-build system strength solutions required as part of the preferred portfolio option. For example, if there are insufficient non-network solutions available, Transgrid will look to new-build network solutions to meet the need.

This list does not include all the possible changes which may impact the preferred portfolio option, but those Transgrid consider more likely to eventuate. System strength is inherently affected by many factors including (but not limited to) delivery of transmission projects, the performance, amount and location of IBR, retirement and operation of existing synchronous generation and relative costs of technologies. It is not possible to model for all scenarios and permutations. Instead, the level and location of non-network solutions procured is intended to undergo adjustments each year to achieve an efficient outcome and account for discrepancies between the modelled state of the world and the actualised build-out.

After six months following the completion of the PACR, Transgrid will assess if there has been a material change in circumstances and the activation of a re-opening trigger. If an MCC has occurred, Transgrid would notify the AER and propose a course of action to determine if the preferred option of this RIT-T remains the most net beneficial option considering the changed circumstances. The AER would then approve, reject or modify the proposed course of action, noting significant delays to the procurement of solutions could jeopardise Transgrid's ability to provide an adequate amount of system strength at the required time.

10. PACR conclusion

Portfolio option 2 (enhanced portfolio) is the preferred credible portfolio option for this RIT-T. This portfolio is a blend of network and non-network system strength solutions including (by 2032/33):

- ten network (Transgrid) synchronous condensers, each providing 1,050 MVA fault current;
- seven synchronous condensers for remediation of the New England REZ, each providing 1,050 MVA fault current (the party responsible for delivering these synchronous condensers is dependent on EnergyCo's system strength strategy for the REZ);
- either four smaller non-network synchronous condensers (275 MVA fault current) or 200 MW of grid-forming BESS in 2027/28 for Hunter-Central Coast REZ with the preferred technology and proponent selected through a procurement process;
- 5 GW of grid-forming BESS;
- 650 MW of existing and new synchronous generation upgraded to enable synchronous condenser capability; and
- re-dispatch of existing and committed hydro, gas and coal units.

Portfolio option 2 is expected to deliver the best outcome of the three credible portfolio options assessed under this RIT-T due to its greater resilience to different states of the future world (in comparison to portfolio option 1) and materially higher net market benefits than portfolio option 3.

We consider that the preferred option satisfies the RIT-T.

Portfolio options 4 and 5 are not currently credible. However, if the accelerated procurement Transgrid synchronous condensers is confirmed as credible, either portfolio option 4 or 5 would become the most preferred option in this RIT-T, depending on the extent of acceleration considered credible. This is because portfolio option 4 and portfolio option 5 exhibit the highest net market benefits, deliver a more resilient power system and enable the earliest achievement of 100% instantaneous renewables in NSW, which supports government emissions reduction goals.

Following publication of the PACR, Transgrid will continue work to identify a credible pathway to deliver Transgrid synchronous condensers as soon as possible, to minimise power system security risks and maximise market and consumer benefits.

We note that in all portfolio options, risks of gaps in system strength remain. Under the Improving Security Frameworks rule change, AEMO will enable (or 're-dispatch') synchronous machines in the operational timeframe to seek to close forecasted gaps in system strength. Transgrid will support AEMO and other relevant parties to manage the risks of insufficient system strength, for example with regards to the scheduling of critical planned outages of transmission lines. In recognition of the urgency of system strength requirements, Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders to enable the regulatory and procurement process to progress as quickly as possible. Following publication of the PACR, Transgrid will continue this work to deliver Transgrid synchronous condensers as soon as possible, with the goal to reduce power system security risks and maximise net market benefits.

This PACR represents the final stage in the RIT-T process.

Parties wishing to raise a dispute notice with the AER may do so prior to 18 August 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER within 40 to 100 days, after which the formal RIT-T process will conclude.

10.1. Next steps for the preferred portfolio of solutions

Following the conclusion of this RIT-T, Transgrid will commence procurement and regulatory processes for individual solutions required as part of the preferred portfolio of system strength solutions, including:

- network solutions (Transgrid synchronous condensers): Transgrid's current revenue determination has a contingent project for this RIT-T. A key next step is to submit a contingent project application to the AER once all triggers have been met.
- non-network solutions: Portfolio option 2 determined which types of non-network solutions are eligible to participate in procurement processes. Following procurement processes and for eligible contracts, Transgrid will seek a determination from the AER on whether Transgrid's proposed expenditure on non-network solutions meet criteria indicating efficient and prudent expenditure. If successful, this will be followed by the execution of contracts between Transgrid and proponents.

10.1.1. Flexibility in non-network procurement

The optimal composition of our preferred credible portfolio option 2 is driven through a techno-economic co-optimisation of network and non-network solutions, including synchronous machines and grid-forming batteries, using best available information at the time of analysis.

Future system strength requirements will almost certainly change on a yearly basis going forward, for example as AEMO updates the IBR forecast in its annual System Strength Report. Given this, Transgrid intends to use non-network solutions to provide flexibility in how the preferred portfolio option identified through this RIT-T will meet these evolving needs. During the ongoing contracting process for system strength, Transgrid will use the best information available to determine the specific location, quantum and timing of non-network solutions.

For example:

- if IBR build-out is slower than forecast, or we require less system strength support than expected, it may reduce the need;
- if a particular grid-forming BESS is more effective than assumed, it may reduce the overall capacity (MW) of grid-forming BESS that we need to procure; and
- if a non-network solution is delayed or found to be no longer technically or commercially feasible, we may seek alternative solutions (which may have different size, timing, location and/or technology) to fill the gap.

A MCC related to non-network solutions is only expected to be triggered if the portfolio of non-network solutions which is able to be contracted varies from the PACR enough to change the optimal number of new-build system strength solutions required as part of the preferred portfolio option. For example, if there are insufficient non-network solutions available, Transgrid will look to new-build network solutions to meet the need. Transgrid has identified re-opening triggers for this RIT-T in Section 9.3.

10.1.2. Next steps for non-network procurement

Following the PACR, Transgrid will work to procure non-network services from proponents of these technologies:

- **grid-forming BESS:** Transgrid anticipates that the first tranche of contracts for stable voltage waveform support from grid-forming BESS are required for 2026/27. Transgrid expects to initiate procurement for this first tranche in late 2025.
- **synchronous machines:** The first tranche of contracts for synchronous system security services are required from 2 December 2025. Transgrid has already commenced engagement with eligible providers to procure this first tranche.

Next steps for the first tranche of grid-forming BESS contracts, and future tranches of synchronous machine contracts will be communicated by email to all eligible parties who have previously submitted a EOI to provide the relevant system strength service.

If you have not previously submitted an EOI for your project(s), or there have been material changes to your project since your EOI, you may submit a new or updated EOI at any time using the documentation on Transgrid's website[67]. Please also advise us if the contact person named on your most recent EOI submission has changed.

Transgrid will conduct a detailed technical and commercial assessment prior to contracting. This assessment will include, where required, detailed power system analysis to select and validate the specific portfolio of solutions that can achieve stable voltage waveforms, and an assessment of prudency and efficiency against the AER's System Security Network Support Payments Guideline. Transgrid expect contracts for stable voltage waveform support from a grid-forming battery would only be offered if the project can meet the technical performance requirements as set out on our website.[68]

For each tranche, Transgrid will procure non-network solutions that comprise the most prudent and efficient non-network portfolio available at the time.

[67] Transgrid, Meeting system strength requirements in NSW: webpage
[68] At the time of publication, the latest document was published on 17 June 2024, accessed on Transgrid's website with the label 'Technical performance and power system modelling requirements for grid-forming BESS',

Appendix A – Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of Clause 5.16.4(v) of the National Electricity Rules version 232.

Table 28. Compliance checklist of PACR with NER version 231

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(v)	The project assessment conclusions report must set out:	-
	(1) The matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) A summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties	
5.16.4(k)	A RIT-T proponent must prepare a report, which must include:	-
	(1) a description of each credible option assessed;	Sections 7, 8 and 6.7
	(2) a summary of, and commentary on, the submissions to the project assessment draft report;	Section 3.1 and Appendix D
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Sections 5, 7 and 6.7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Sections 5 and 6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Appendix F.9
	(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);	Transgrid have co-optimised the energy market across the NEM with system strength requirements for NSW. The overwhelming benefits are associated with avoided system strength gaps to the minimum level leading to involuntary load curtailment. These benefits are expected to arise within NSW. There are also energy market benefits associated with re-dispatch and deployment of grid-forming batteries which will arise across the NEM including NSW. These benefits have been estimated in Section 7 and Section 8 in aggregate across all regions (including NSW) and they have not been separated out by region as these benefits are relatively small in comparison to avoided involuntary load curtailment.
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Sections 7, 8 and 6.7
	(8) the identification of the proposed preferred option;	Section 10
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:	Sections 7 and 10

	(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.	The proposed preferred option will include a system strength solution connected to Ausgrid's distribution network. The finalised system strength solution will be determined through a procurement process between synchronous condensers and grid-forming batteries. Transgrid has engaged Ausgrid and will continue to engage in Joint Planning Activities during the procurement process.
	(10) the RIT reopening triggers applying to the RIT-T project.	Section 9.3
5.16.4(l)	If a Network Service Provider affected by a RIT-T project elects to proceed with a project which is for reliability corrective action, it can only do so where the proposed preferred option has a proponent. The RIT-T proponent must identity that proponent in the project assessment draft report.	Network synchronous condensers are to be delivered by Transgrid. For non-network solutions including re-dispatch, grid-forming BESS and upgrades to synchronous machines, the proponent has not been named in this PACR (nor the PADR) due to requested confidentiality and to facilitate competition during procurement. The proponent for solutions to remediate the New England REZ will be identified through joint planning with EnergyCo.
Binding elements for the PACR from the Cost Benefit Assessment Guidelines	When publishing the Project Assessment Conclusions Report, RIT–T proponents are required to:	-
	Publish, in addition to a summary of submissions, any submissions received in response to the Draft Report, unless marked confidential.	See https://www.transgrid.com.au/projects-innovation/meeting-system-strength-requirements-in-nsw/
	Date the Conclusions Report to inform potential disputing parties of the timeframes for lodging a dispute notice with the AER.	See cover page.
	If a RIT-T proponent receives any confidential submissions on its Draft Report, it must consider working with submitting parties to make a redacted or non-confidential version public.	N/A - No confidential submission were received.

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

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

B.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.

B.2 PSCAD™ validation of available fault level method

PSS®E assesses stable voltage waveform requirements using the AFL methodology outlined in the System Strength Impact Assessment Guidelines. This is consistent with guidance from AEMO for planning purposes. This methodology has been adopted by AEMO as a proxy for system strength. However, for the efficient level of system strength, this methodology does not account for the four criteria which define stable voltage waveform discussed in Section 2.1. Transgrid has compared the AFL methodology against the EMT methodology through an assessment of the synchronous fault level contributions of synchronous condensers to achieve stable voltage waveform in different areas of the NSW network.

The assessment found general agreement between the two methodologies at a state-level, confirming the AFL methodology as a suitable estimate for fault level requirements at a planning level. However, at more granular scales, some areas were found to need a contribution either higher or lower than calculated using the AFL method to achieve stable voltage waveform. This is due to factors that the AFL methodology cannot take into consideration (for e.g. tuning of Static VAR Compensators). As a result, it was considered prudent to test the portfolio of solutions could support a stable voltage waveform both on a state level and in specific high renewable areas of the network using the EMT method in PSCAD™. This reduces the risk of inefficient procurement in system strength solutions for the efficient level if solutions had lower or higher contributions than calculated using the AFL method.

B.3 Transgrid enhanced the use of ‘boost factors’ for grid-forming batteries

Transgrid recognises that fault current is only a proxy for the provision of stable voltage waveform support and acknowledges that grid-forming batteries are disadvantaged for contributing to system strength when assessed using the AFL method due the technology’s limited current overload capabilities. 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). In the PADR, Transgrid used a ‘boost factor’ to account for the disadvantage that grid-forming BESS face when stable voltage waveform support is ‘valued’ using solely the AFL method. This approach has been enhanced for the PACR.

The boost factor was calculated via PSCAD™, by adding IBR until stable voltage waveform was no longer achieved in the wide area model, then comparing the amount of grid-forming BESS required to re-stabilise the model to the amount of synchronous condensers required to re-stabilise the model.

In the PADR, all grid-forming batteries were assumed to have a ‘boost factor’ of 3.1, effectively tripling its contribution when assessed on a fault current basis, as discussed in PADR Baringa report[69]. For the PACR, Transgrid has collaborated with grid-forming inverter suppliers and refined this value based on each supplier’s equipment. Boost factors for the PACR ranged between 2.6 and 4.1 based on the individual supplier, although two grid-forming inverter models supplied were found to have no capacity to provide stable voltage waveform support.

Each grid-forming battery solution in the PACR was assigned a boost factor based on the supplier chosen for the project. If a project had not yet confirmed a supplier, a boost factor of 2.6 was assumed. Although two suppliers were found to have no benefit to support stable voltage waveform, the technology is improving quickly, and it is considered likely for all suppliers to provide some benefit in the near future.

For ‘targeted’ grid-forming BESS, which are modelled as the entire CAPEX cost, a boost factor of 4.1 was assumed, as we have assumed that non-network proponents (or Transgrid) would select a grid-informing inverter with the best capacity to support stable voltage waveform.

B.4 ‘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 (model infeasibility due to solve time limits), 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 final portfolio

[69] Baringa, 25 June 2024, Meeting system strength requirements in NSW - Baringa Market Modelling Report For Transgrid's Project Assessment Draft Report (PADR)

with integer synchronous condenser build path is then fed into PLEXOS' Short-Term dispatch model to calculate market benefits for each option.

B.5 Staggered entry of synchronous condensers to represent real-world delivery limitations

In the PADR, if multiple synchronous condensers were identified as optimal to build in an individual year, they are each modelled as being built on the first day of the year. As discussed in Section 6.5, from engagement with suppliers following the PADR, Transgrid understand there are real-world constraints which require synchronous condensers to be staggered by approximately 1.5-month intervals. This duration was informed by engagement with suppliers and assumes more than one supplier is selected.

Transgrid implemented this constraint through a post-processing methodology. The portfolio optimisation provided a build-path for system strength solutions on a yearly basis. We adjusted this build path by manually setting the earliest date each synchronous condenser could be installed and then re-running the model with the solutions already locked in to determine the net market benefits.

Appendix C – NPV sensitivity results

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

- 25 percent higher and lower VER values, (i.e., consistent with the MCE guidance);[70]
- 30 percent higher and lower VCR values (i.e., consistent with the AER's state level of confidence);[71]
- 25 percent higher and lower assumed synchronous condenser costs (both capital and operating costs);
- 25 percent higher and lower grid-forming BESS upgrade costs (both capital and operating costs); and
- lower and higher commercial discount rates (as discussed in Section F.10).

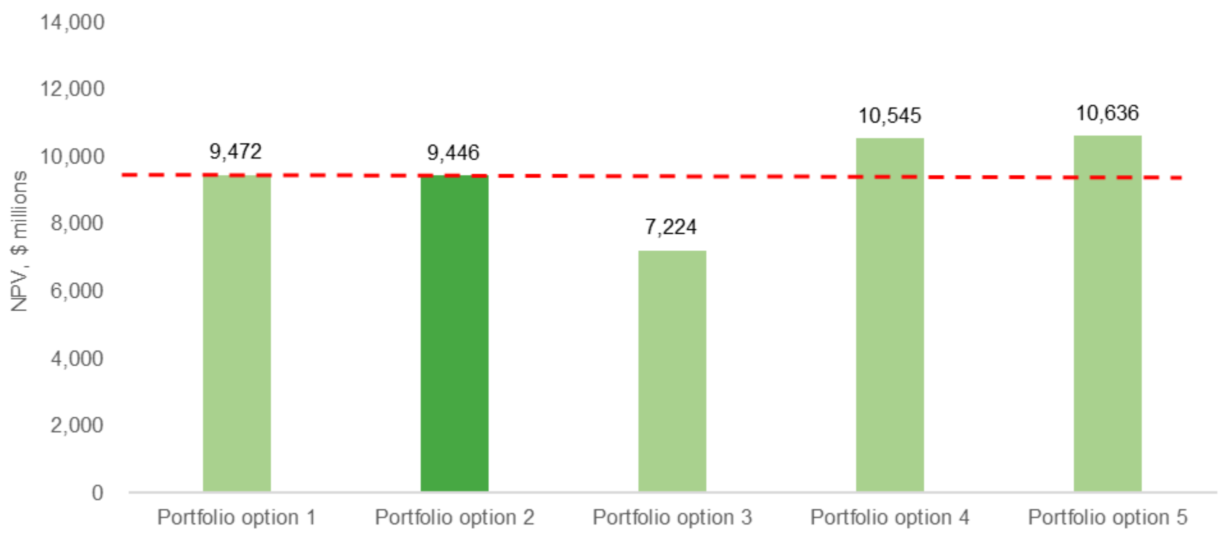
C.1 Higher and lower assumed value of emissions reduction

This sensitivity tested two scenarios which varied the value of emissions reduction. The two tests are:

- 25 percent higher value of emissions reduction
- 25 percent lower value of emissions reduction

The results of the 25 percent higher value of emissions reduction sensitivity is shown in Figure 38. The results do not change the order of the credible options for this RIT-T, portfolio options 1 and 2 both rose by 6.8 percent. Portfolio option 3 NPV increased by 9.1 percent. Portfolio options 4 and 5 rose by 6.1% and 6.2% respectively.

Figure 38. Results of high value of emissions reduction sensitivity

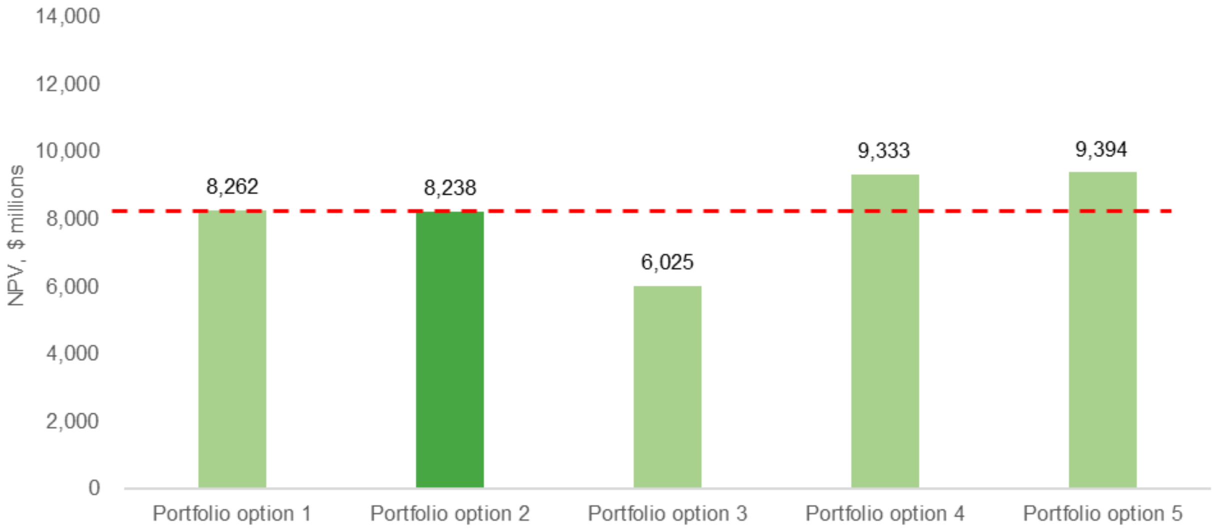


The results of the 25 percent lower value of emissions reduction sensitivity are shown in Figure 39.

70 AEMC, MCE statement about the interim value of greenhouse gas emissions reduction

71 AER, September 2020, Widespread and long duration outages – values of customer reliability - Final conclusions

Figure 39. Results of 25 percent lower value of emissions reduction sensitivity



C.2 Higher and lower assumed value of customer reliability

This sensitivity tested two scenarios which varied the value of consumer reliability. The two tests are:

- 30 percent higher value of consumer reliability
- 30 percent lower value of consumer reliability

The results of the 30 percent higher and lower value of consumer reliability sensitivity are shown in Figure 40 and Figure 41. The results do not change the order of any of the portfolio options.

As portfolio option 3 has the most amount of system strength gaps and the analysis only valued the reduction in differences from this level, the NPV for portfolio option 3 did not change (see appendix F.3. for further details).

The change in values were consistent across both sensitivities, increasing by approximately 6.2% for portfolio options 1 and 2 and 8.2% and 8.1% for portfolio options 4 and 5.

Figure 40. Results of 30 percent higher value of consumer reliability sensitivity

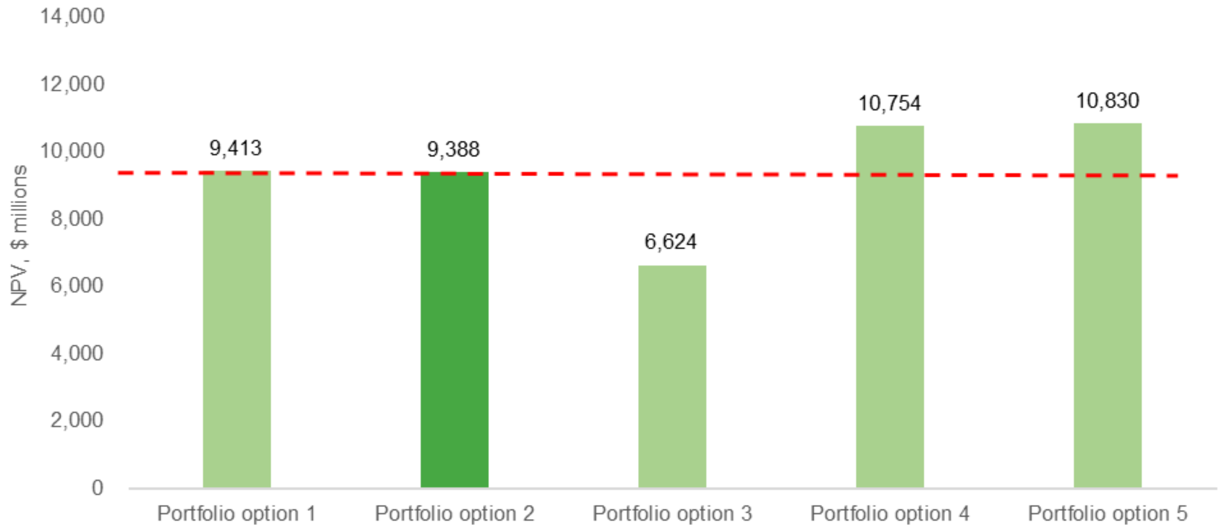
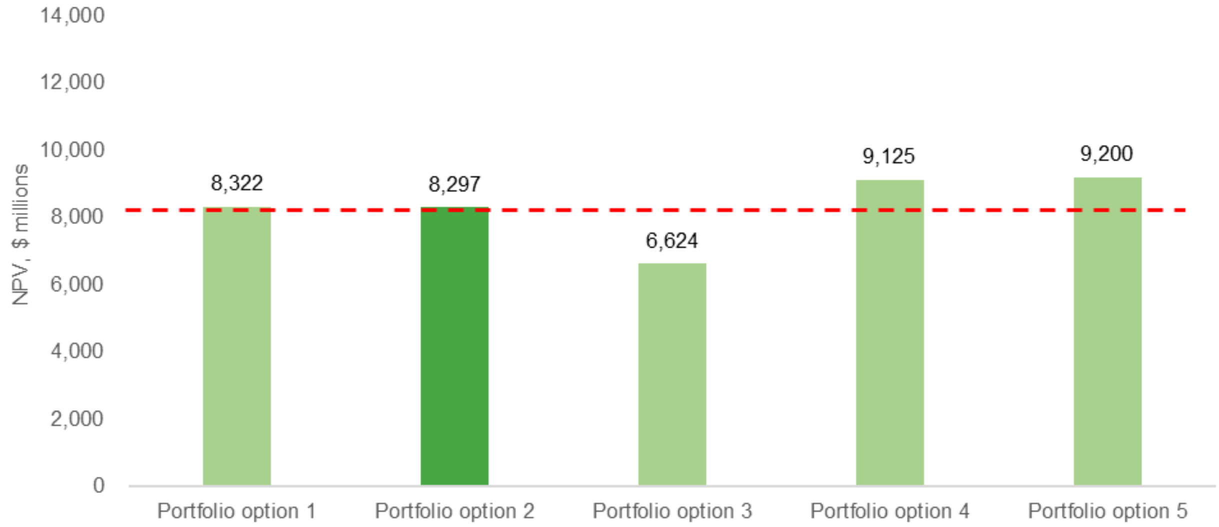


Figure 41. Results of 30 percent lower value of consumer reliability sensitivity



C.3 Higher and lower assumed synchronous condenser costs

This sensitivity tested two scenarios which varied the cost of synchronous condensers including both CAPEX and OPEX. The two tests are:

- 25 percent higher cost
- 25 percent lower cost

The results of the 25 percent higher and lower synchronous condenser cost sensitivity are shown in Figure 42 and Figure 43. The results do not change the order of any of the portfolio options.

The change in NPV was consistent under both sensitivities for each portfolio option. Each portfolio option changed by approximately 5 percent, the similarity owing to the same number of synchronous condensers required for each portfolio option. The differences between portfolio options are due to a change in the timing of synchronous condenser CAPEX costs.

Figure 42. Results of 25 percent higher synchronous condenser cost sensitivity

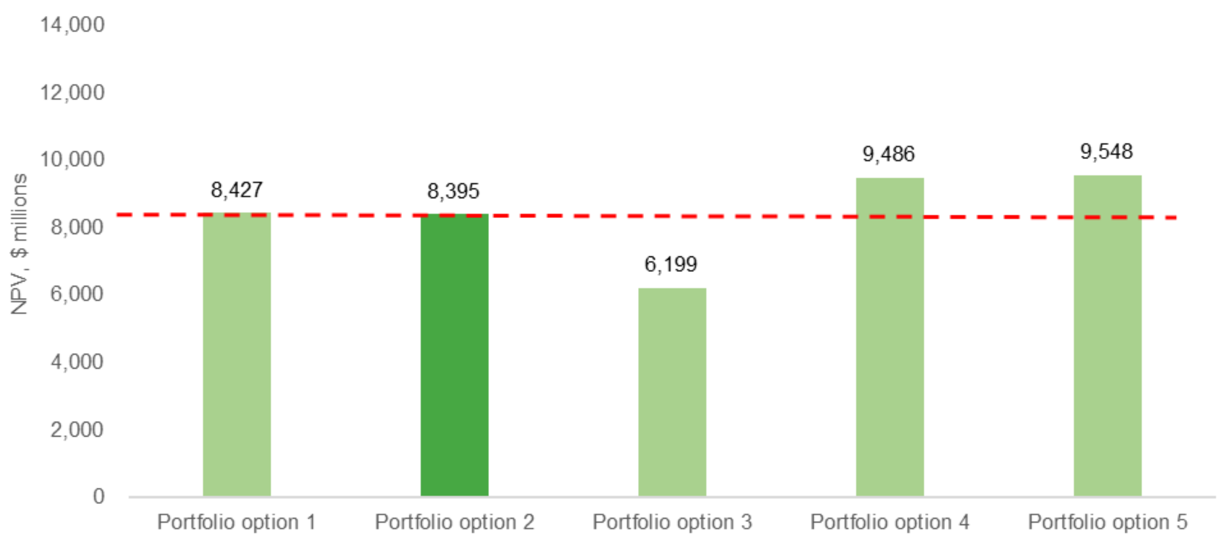
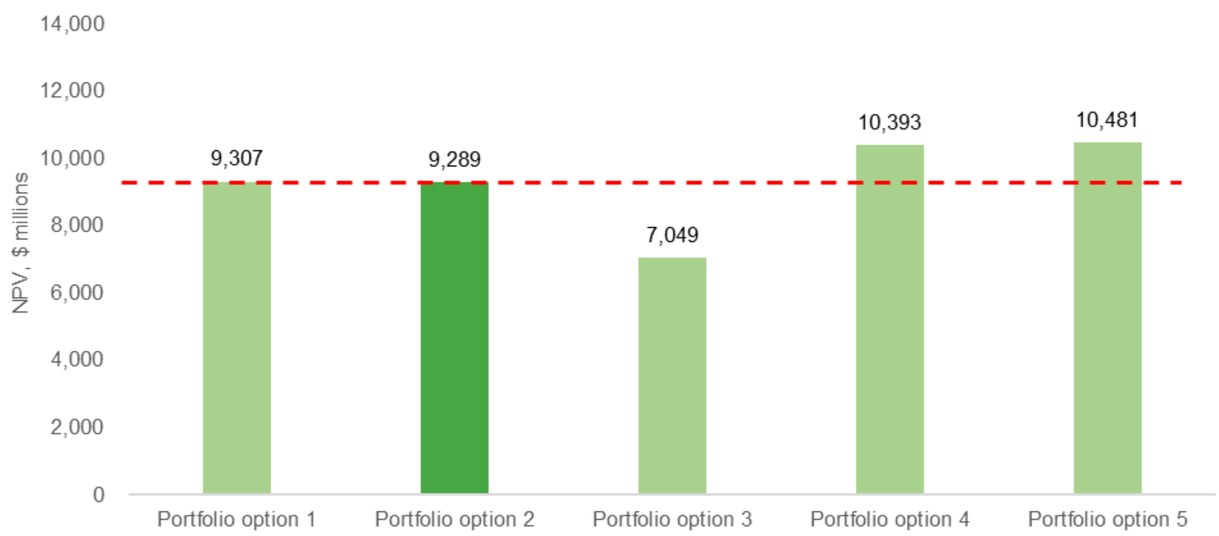


Figure 43. Results of 25 percent lower synchronous condenser cost sensitivity



C.4 Higher and lower assumed grid-forming BESS upgrade costs

This sensitivity tested two scenarios which varied the cost of the upgrade to enable grid-forming. The two tests are:

- 25 percent higher cost
- 25 percent lower cost

The results of the 25 percent higher and lower cost of grid-forming BESS upgrade sensitivity are shown in Figure 44 and Figure 45. The results do not change the order of any of the portfolio options.

The change in NPV was consistent under both sensitivities for each portfolio option. Each portfolio option changed by approximately 5 percent, the similarity is due to the same number of grid-forming BESS required for each portfolio option.

Figure 44. Results of 25 percent higher grid-forming BESS upgrade costs

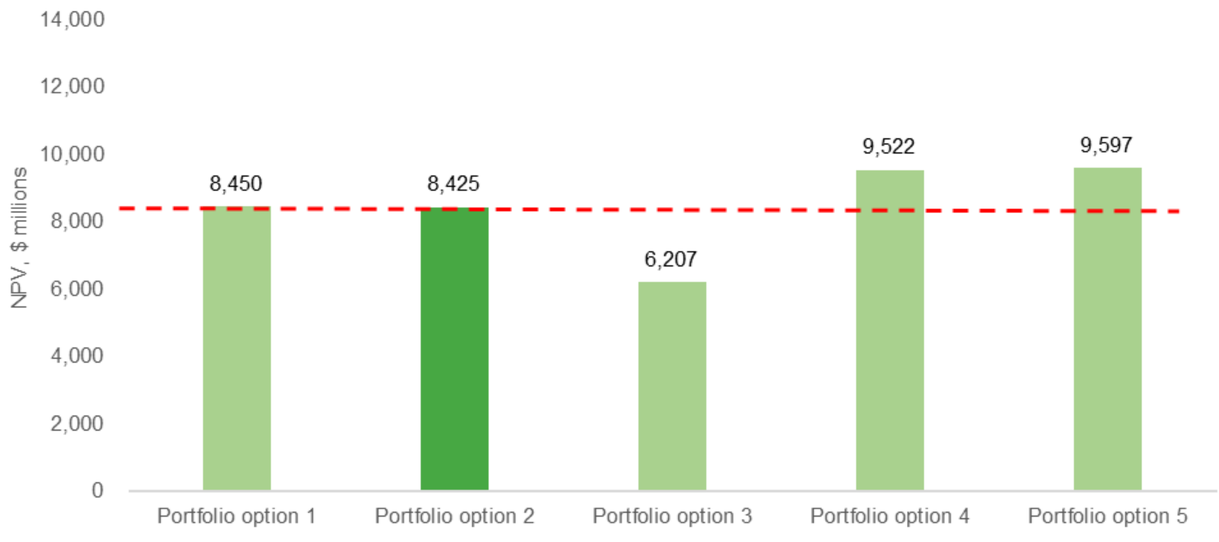
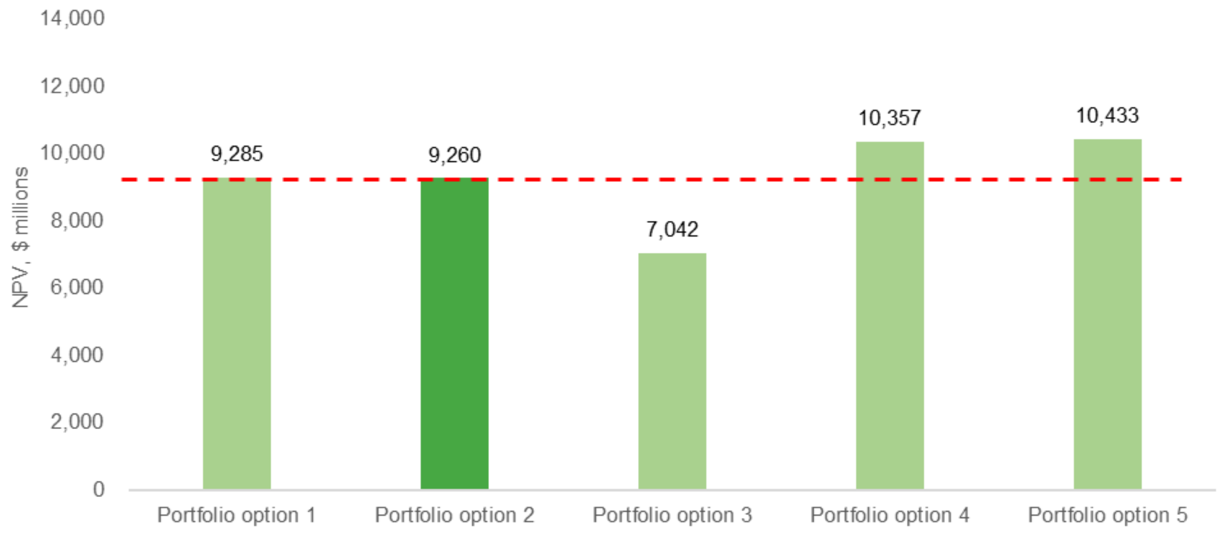


Figure 45. Results of 25 percent lower grid-forming BESS upgrade costs



C.5 Higher and lower assumed commercial discount rate

This sensitivity tested two scenarios which varied the commercial discount rate. The two tests are:

- Using a lower commercial discount rate of 4.18 percent
- Using a higher commercial discount rate of 10.5 percent

The results of the t higher and lower commercial discount rate sensitivity are shown in Figure 46 and Figure 47.

The change in NPV for the commercial discount rate sensitivity was much higher than other sensitivities. For the lower commercial discount rate, the NPV increased by between 44.4 percent and 58.1 percent highlighting a material increase. For the higher commercial discount rate, the NPV decreased by between 34.9 percent and 43.5 percent.

Figure 46. Results of lower (4.18 percent) commercial discount rate sensitivity

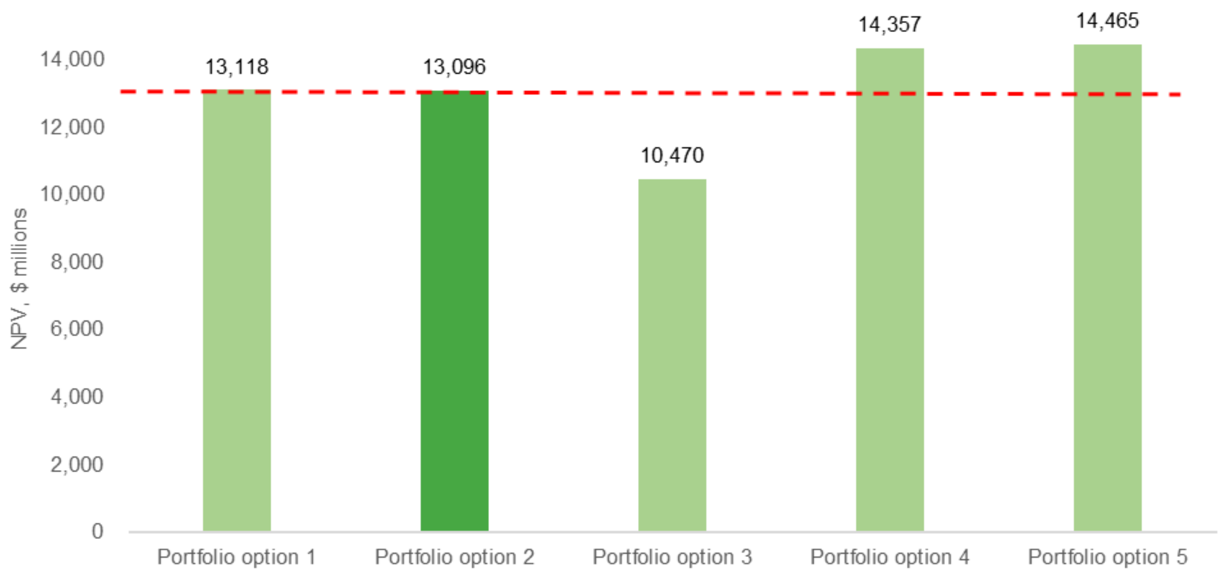
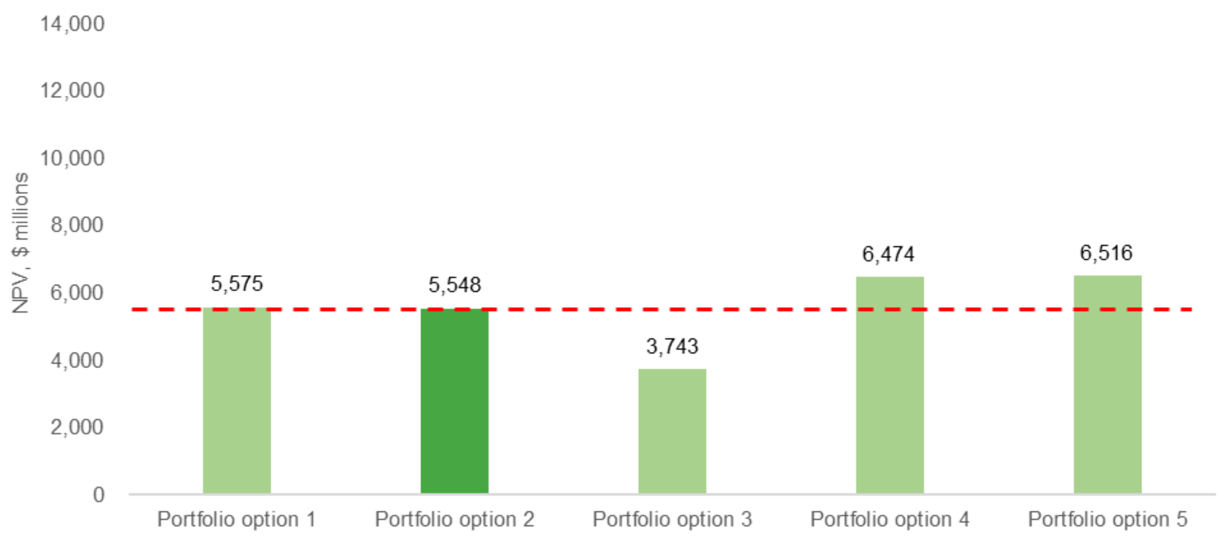


Figure 47. Results of higher (10.5 percent) commercial discount rate sensitivity



Appendix D – Additional detail on all non-confidential points raised through PADR consultation

In addition to the responses to the EOI, we received formal submissions from two parties directly in response to the PADR throughout the six-week consultation period. Both of which have been published on our website. These parties are EnergyCo and Tesla.

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

- The timing and scope of non-network solutions, in particular grid-forming batteries;
- Consideration of recent REZ developments when planning for the efficient level of system strength;
- The broader RIT-T framework; and
- The treatment of the Hunter-Central Coast REZ.

Transgrid also received an email submission from Ausgrid providing additional information for the Hunter-Central Coast REZ, which aided the formation of the assumptions for the PACR modelling.

The key matters raised in non-confidential submissions are summarised and responded to in the following table.

Table 29. Response to submissions from PADR and PADR Supplementary Report

Summary of comment(s)	Submitter(s)	Our response
Timing and scope of non-network solutions, in particular grid-forming batteries		
Grid-forming BESS meet the technical characteristics for providing system strength		
In Tesla's view (as supported by independent reports from AEMO, ARENA, and ongoing global studies that Tesla can share on request) grid-forming BESS assets meet all the technical characteristics for providing system strength and ensuring a stable voltage waveform – and this performance is now widely demonstrated.	Tesla, p 1	We agree that BESS can assist with providing the efficient level of system strength and ensuring a stable voltage waveform, we have identified 5 GW of grid-forming BESS as part of our preferred portfolio option. This is the equivalent of seventeen synchronous condensers for stable voltage waveform support. However, we consider adopting the independent advice and assumptions of Aurecon to be prudent at this stage in light of these assets not yet being proven at scale (particularly in Australia). However, since the PADR, we have undertaken detailed assessments with the PSCAD™ models of proponent grid-forming BESS, to inform our assumptions regarding the performance of grid-forming BESS for stable voltage waveform support. Transgrid requested, but did not receive, further information from Tesla.
Once grid-forming mode (such as Virtual Machine Mode (VMM)) is enabled at the point of grid connection, then BESS assets will provide ongoing system strength support without any need to respond to external enablement signals. This means that non-network solutions can provide system strength whilst also optimised for market needs at any point in time.	Telsa p 1	We agree that grid-forming BESS can provide both services simultaneously and it has been reflected in our modelling both in the PADR and the PACR. Specifically, we have not required that these BESS reserve any headroom for providing system strength and BESS are assumed to contribute towards the system strength requirements without impacting their behaviour in the energy market (or ancillary services markets).

Tesla has mature grid models available for grid-forming VMM in both root-means-squared (RMS) and electromagnetic transient (EMT) environments, which have been the subject to the rigorous assessment under NER 5.3.4A/B and 5.3.9 for NEM connected projects. Tesla's model provides a good base case of what could be provided at scale and should therefore be granted part of the optimal portfolio of solutions as part of the PACR stage.	Tesla, p 2	We have used the models provided by proponents to assess the technical feasibility and effectiveness factors of grid-forming BESS (towards the efficient level requirements) in PSCAD™ as part of the PACR modelling. We also conducted a sensitivity if grid-forming BESS are able to perform better than modelled (see Section 9.1.1).
Additional benefits of non-network BESS solutions not included in the PADR NPV cost-benefit analysis		
Grid-forming BESS are multi-use assets and provide a multitude of market services as well as network support to make them more cost effective than other solutions. Given the flexibility of BESS to have features and functionality updated over the asset life, these services can also change over time to provide optimal co-benefits to the grid and the market.	Tesla, p 1	We agree that grid-forming BESS provide a range of benefits and offer flexibility in how the system strength requirements are met over time. We have assessed the costs and benefits of these solutions consistent with the RIT-T framework and using all available information provided by proponents.
Grid-forming BESS assets support the broader NSW Energy Security Target directly contributing to both reliability and system security objectives – aligning with complementary policy development work that the NSW Government, EnergyCo. and AEMO are managing. Supplementary BESS deployment also aligns with the broader federal priorities under the Capacity Investment Scheme seeking 9 GW of dispatchable capacity across the NEM.	Tesla, p 1	We agree that grid-forming BESS support these various government policies and the NEM's energy transition. We have assumed all policies and targets consistent with the 2024 ISP Step Change scenario, which includes updated renewable energy targets for NSW and the Federal Government's expanded Capacity Investment Scheme.[72] Moreover, our modelling assumes that all grid-following BESS assumed to develop under these schemes have the option of upgrading to be grid-forming. Our modelling assumes that all grid-forming batteries provide energy market benefits, in addition to system strength benefits.
The contribution of grid-forming BESS towards the minimum level requirements prior to 2032/33		
Transgrid should re-consider its consultant's advice 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)." Transgrid, in parallel with AEMO and ARENA, should use this RIT-T process as an opportunity to conduct detailed modelling and support additional 'at-scale' deployments that will provide the confidence that is being sought for a "satisfactory fault current response to enable the safe (and successful) operation of protection equipment in the transmission network".	Tesla, p 2	We agree that this RIT-T should be used as an opportunity to conduct detailed modelling and support additional at-scale deployments. As outlined above, we are aiming to contract with 5 GW of grid-forming BESS by 2032/33. We intend to use this as an opportunity to facilitate careful testing of the performance of these BESS in potentially providing minimum levels of system strength without risking power system stability if their performance is not satisfactory, i.e. our findings provide an opportunity to support at-scale developments to provide confidence without unduly risking system stability. Transgrid's consultant advice on this topic aligns to AEMO's position that grid-forming batteries do not currently provide protection-quality levels of fault current[73]. Under the new non-market ancillary service (NMAS) frameworks as part of the 'improving security frameworks for the energy transition' final rule determination, AEMO are able to procure contracts to support building understanding and confidence

[72] AEMO, June 2024, *2024 ISP*
[73] AEMO, December 2024, 2024 Transition Plan for System Security

		managing a low-emissions system ('Type 2' NMAS contracts).[74] This provides a more appropriate pathway for testing and building confidence in grid-forming BESS performance and capability to contribute towards minimum level requirements.
We understand the need for a risk-averse approach as a network operator to ensure safe and secure grid operation, but given the size of the opportunity identified through this RIT-T, it would be short-sighted to overlook a technology, such as grid-forming BESS, that is at the cusp of technical acceptance with network engineers simply due to unfamiliarity, without first seeking to fully address the unknowns through additional studies and technical due diligence together with technology providers such as Tesla.	Tesla, p 2	The assessment of grid-forming BESS has been a key part of this RIT-T and, as outlined above, we are aiming to contract with 5 GW of grid-forming BESS by 2032/33. To fully address the current uncertainties regarding the use of grid-forming BESS at scale before committing to new assets would take a significant amount of time and cannot be done without risking power system security. Transgrid must take a prudent and pragmatic approach to ensuring system strength can be maintained throughout the energy transition, while in parallel working to assess unknowns related to grid-forming BESS. The staged approach recommended in this PACR allows us to meet our obligations and maintain power system security in NSW, whilst also taking the opportunity to facilitate careful testing of grid-forming BESS through their inclusion as a credible solution to meet efficient level requirements.
As a useful precedent, we point to the approach taken by the Victorian Government that had originally allocated its system strength funding only to synchronous condensers, before also allowing grid-forming battery projects to tender alongside – with the Koorangie BESS contracted for system strength services.	Tesla, p 2	The Koorangie BESS in Victoria is specifically targeted at increasing the renewable hosting capacity of the Murray River REZ.[75] We are aiming to contract with 5 GW of grid-forming BESS by 2032/33 to address the efficient system strength requirements in NSW.
Synchronous condensers are not a 'no-regret' solution		
Non-network solutions can provide system strength whilst also optimised for market needs at any point in time. This further improves the commercial viability of grid-forming BESS assets as a non-network solution, and removes the justification that synchronous condensers are in fact a 'no-regret' solution – given they provide less value as a single-use, single-purpose asset.	Tesla, p 1	As outlined above, we agree that grid-forming BESS can provide both services simultaneously and have reflected this in our modelling (in both the PADR and the PACR). Specifically, we haispve not required that these BESS reserve any headroom for providing system strength and BESS are assumed to contribute towards the system strength requirements without impacting their behaviour in the energy market (or ancillary services markets). Transgrid referred to 'no-regret' synchronous condensers in the PADR specifically for the five accelerated synchronous condensers identified under portfolio option 2. They were considered 'no-regret' as they are identified under all portfolio options as the only credible solution to close gaps in the minimum level of system strength. Despite not operating in the energy market, Transgrid's modelling demonstrates that synchronous condensers provide a high MVA contribution to system strength at

74 AEMC, 28 March 2024, National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 - Final Rule Determination

75 Edify Energy, Koorangie Energy Storage System: webpage

		relatively low cost (considering fixed, variable and emissions costs).
Consideration of recent REZ developments when planning for the efficient level of system strength		
EnergyCo requests Transgrid to consider system strength planning based on 3.98 GW of VRE for the South West REZ by 2030		
EnergyCo understands that Transgrid has an obligation to provide system strength services in accordance with AEMO's forecasts under NER clause S5.1.14. However, NSW Government policy provides for a higher level of variable renewable energy (VRE) in the South West REZ from 2029/30 than forecast in the 2024 ISP. The South West REZ Access Scheme, which the Minister declared in April 2024, has an initial allocation of up to 3.98 GW of VRE capacity of access rights. Pending the outcomes of the AEMO Services Tender Round 5, EnergyCo could grant the full 3.98 GW capacity of access rights to generators in early 2025. VRE projects in the REZ may seek energisation dates aligning with the energisation of Transgrid's Project Energy Connect, and EnergyCo would expect the majority of this generation to be energised by a similar 2029-30 timeframe to AEMO's ISP, after Humelink and the northern section of VNI West reach energisation. As such, the system strength services currently planned in the PADR for this region are unlikely to be sufficient to meet the generation development anticipated by EnergyCo.	EnergyCo, pp 1-2	As outlined in Section 2, Transgrid has used its own IBR forecast based on AEMO's latest (2024) System Strength Report and most recent information. The IBR forecast included an increase in South West REZ capacity from 2 GW to 2.6 GW compared to the 2024 System Strength Report. Transgrid understands the recent access rights tender awarded 3.56 GW of transfer capacity including wind, solar and BESS however these projects are not considered anticipated or committed at this stage and therefore have not been included in the base case for this RIT-T. However, to demonstrate the robustness of the preferred portfolio to the allocated access rights projects, a South West REZ Access Rights sensitivity was included in this RIT-T in Section 9.1.3. The sensitivity indicated system security contracts with grid-forming BESS may be required if the full capacity of the Access Rights holders is constructed.
The full capacity of VRE that can be allocated access rights is higher than the AEMO IBR forecasts in the region, which specify 307 MW at the Buronga node and 2567 MW at the Darlington Point node by 2030. EnergyCo requests Transgrid to consider system strength planning based on 3.98GW of VRE by 2030.	EnergyCo, p 2	
The aggregate maximum capacity cap for South West REZ may increase in the future, through headroom assessments that could commence as soon as the initial allocation of access rights is completed in early 2025. This headroom may originate from BESS projects within the REZ reducing curtailment levels through peak shaving, or through additional network upgrades which unlock or decongest additional capacity. EnergyCo therefore suggests that the system strength needs in this region be reviewed regularly, and any changes be detailed in joint planning meetings between the organisations.	EnergyCo, p 2	We agree the realised build-out of IBR should be monitored regularly in the South West REZ and across NSW more broadly to ensure sufficient system strength is procured.
The broader RIT-T framework		

The RIT-T framework is no longer fit for purpose		
The RIT-T is no longer fit for purpose – the process takes far too long to be practical, and the current application of the 'total economic cost' framework fails to recognise today's technology and commercial models.	Tesla, p 3	We are required to apply the RIT-T under the current NER, and we have done so in full compliance with the test and associated AER guidance (including that provided specifically for system strength RIT-Ts in Guidance on the efficient management of system strength framework).
Non-network options remain consistently undervalued in the RIT-T framework. To Tesla's knowledge, there have been no successful non-network solution projects completed under any RIT-T to date without requiring external funding arrangements (e.g. ARENA or Government grants). This is because the RIT-T fails to value the full suite of benefits BESS provide, and forces a total economic cost approach that inflates their cost relative to alternatives.	Tesla, p 3	We have captured the costs and benefits of these solutions in-line with the current AER RIT-T guidelines. The preferred solution has identified 5 GW of grid-forming BESS in addition to other non-network solutions including re-dispatch and conversion of existing synchronous generators.
Even if the new system strength rules recognise the capabilities and benefits of grid-forming BESS providing system strength services, network companies may face additional barriers in valuing these benefits based on the RIT-T assessment guidelines, undermining the scheme's benefits: delaying the connection process, unfairly disadvantaging the value proposition of BESS, and adding unnecessary costs to the total system (with less efficient solutions ultimately progressed).	Tesla, p 3	
BESS have a proven ability to reduce prices in wholesale energy and FCAS markets. These benefits are excluded due to being 'wealth transfers', but this ignores benefits from improved liquidity and/or the removal of price distortions.	Tesla, p 4	Benefits from improved liquidity and/or the removal of price distortions are not recognised under the RIT-T. Changes in FCAS costs have not been included as they are unlikely to be materially different between portfolio options or in the selection of the preferred option.
BESS have the most value in FCAS markets, but RIT-Ts typically only model wholesale energy changes occurring in dispatch, considering FCAS a negligible market benefit class.	Tesla, p 4	The magnitude of BESS is consistent across all modelled portfolio options so the difference in FCAS market benefits is not expected to be material.
Treatment of the Hunter-Central Coast REZ		
There has not been any consideration of the potential impacts of Hunter-Central Coast REZ on the preferred portfolio of system strength. Understanding that Hunter-Central Coast REZ is set to reside within Ausgrid's network with interfaces to Transgrid's network via Newcastle BSP and Muswellbrook BSP, the impact of distribution connected generation and system strength solutions may not be as great when directly interfaced to the transmission network, yet I think that Hunter-Central Coast REZ should be considered as a part of the analysis. As distribution networks will play an increasingly crucial role in the energy transition and maintaining system strength	Ausgrid, email	Transgrid received its IBR forecast from Baringa Partners based on the 2024 AEMO System Strength Report and incorporating recent market developments. This IBR forecast included 1.4 GW of IBR in the Hunter-Central Coast REZ. This has been assigned to the distribution network operated by Ausgrid. Transgrid has engaged Ausgrid in joint planning activities to use the latest information of network topology and connecting generators to inform PSCAD modelling which was used to manually assess the system strength solutions for the REZ.

as the system becomes more decentralised, the need for active management and coordination between distribution and transmission network service providers is essential for ensuring a stable and resilient system and drive efficient investment for system strength solutions		

Appendix E – Technical feasibility of solutions

Transgrid requested proponents of new solutions provide a power systems modelling package (including PSCAD™ models) to facilitate a detailed assessment of the technical feasibility of any new generator or system strength solution. This process sought to ensure that the proposed solutions are robust and capable of meeting the required technical specifications for providing system strength. For existing synchronous generation, the capacity to provide system strength is well-understood and is considered technically feasible. Transgrid modelled all solutions in PSS®E to assess and calculate their system strength contributions.

E.1 Network synchronous condensers

Transgrid has assessed the credibility of network synchronous condensers through detailed feasibility studies of synchronous condensers at various Transgrid substations along with market sounding of synchronous condenser original equipment manufacturers, to refine cost and schedule estimates. The technology is considered mature for system strength provision, used in Australia and internationally.

Feasibility studies assessed site specific costs for the installation of a synchronous condenser and associated equipment. The studies considered the cost, timing of the activities, environmental issues, risk analysis and practicality of being able to complete the works. The studies provided a suite of refined cost estimates for synchronous condensers relative to the PADR.

The feasibility study for Sydney West site identified challenges to accommodate a synchronous condenser due to higher estimated costs and high risks of delay; this resulted in Kemps Creek being considered the preferred location for synchronous condensers in the area of the Sydney West system strength node.

E.2 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.

Transgrid assessed the credibility of proposed non-network synchronous condensers through the EOI process which required proponents to provide technical and commercial information about their proposed solutions. Transgrid will update its analysis and undertake additional technical due diligence prior to contracting to resolve any remaining uncertainties of proposed non-network synchronous condensers.

Project schedules provided by proponents were validated against Transgrid's market-sounding and in-house experience. Transgrid amended schedules based on in-house experience and latest information regarding the expected timelines for completing the regulatory process under this RIT-T which reflects when proponents are likely to receive financial certainty. These adjustments are considered prudent, given the potential consequences of delays to synchronous condenser deployment and to reflect Transgrid's assessment of what is deemed 'highly likely' based on the information provided.

E.3 Grid-forming batteries

Grid-forming batteries hold significant potential to co-optimise system strength provision with other market benefits. Equally, grid-forming inverter technology is relatively novel and has not yet been deployed and tested at significant scale for the provision of system strength services. Comprehensive power system and protection studies need to be undertaken to confirm the effectiveness of grid-forming battery technology to provide system strength support to the minimum level, this is consistent with treatment during the PADR.

This is consistent with advice from AEMO in late 2024. Specifically, in December 2024, AEMO published the 2024 Transition Plan for System Security[76] and commented on the potential for grid-forming batteries for the provision of system strength. The report identifies that the efficient level of system strength *"may be met by a variety of existing or new technologies, including grid-forming inverters"*. However, *"minimum levels of system strength must be provided by protection quality fault current, which grid-forming inverters have not yet demonstrated capability to provide"*. This is also consistent with AEMO's position as published in the May 2024 update to the 2023 ESOO [77].

Independently, Transgrid engaged Aurecon to undertake an assessment of the maturity of grid-forming BESS for system strength support[78]. 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.[79]
- grid-forming BESS are sufficiently mature for stable voltage waveform support, up to a maximum of 50 percent 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 was published alongside the PADR. An additional source of relevant information on the topic of grid-forming batteries and protection system operation was published by Sandia National Laboratories in April 2024.

Consistent with Transgrid's PADR market modelling, grid-forming batteries have been excluded from contributing to the minimum fault level requirements until 2032/33 in the PACR modelling. However,

[76] AEMO, December 2024, 2024 Transition Plan for System Security
[77] AEMO, May 2024, Update to the 2023 Electricity Statement of Opportunities
[78] Transgrid, 04 March 2024, Advice on the maturity of grid forming inverter solutions for system strength
[79] 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.

Transgrid has not explicitly applied Aurecon's recommended 50 percent limit for the efficient level within the PACR 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, in earlier years, there are high minimum level requirements and low efficient level requirements on account of lower levels of IBR connected to the grid. Although BESS may be contributing more than 50% of the efficient level, the contribution to system strength at the node is well-below 50% when both the minimum and efficient levels are considered, and this situation is acceptable.

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 5 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.

AEMO in collaboration with TNSPs and ARENA are already focussed on increasing understanding of the ability for grid-forming inverters to provide protection quality fault current to enable grid-forming BESS to contribute to the minimum level of system strength[80]. Transgrid will monitor the evolution and progress of grid-forming BESS, recognising the potential of the technology for system strength. In the event sufficient progress is made to demonstrate capacity to contribute to the minimum level at scale, this will be considered a material change in circumstance trigger.

E.4 EOI-proposed grid-forming batteries for stable voltage waveform support

Transgrid used the Electromagnetic Transient (EMT) methodology with PSCAD™ to assess the technical feasibility of grid-forming BESS solutions to contribute to the efficient level for system strength. Transgrid required all proponents to submit a Single Machine Infinite Bus (SMIB) model, to be tested against the criteria specified in the technical specification published alongside the PADR[81]. Each proponent's SMIB model was included into Transgrid's wide area model including all committed, anticipated and existing projects across New South Wales, Queensland, Victoria and South Australia. Transgrid assessed the model with and without each project to determine if a project had a detrimental or beneficial impact upon the stabilisation of IBRs. Any project with a detrimental impact (as modelled in PSCAD™) was not considered technically feasible.

High-level EMT network studies for the PACR showed the capacity for grid-forming batteries to support stable voltage waveform over-long distances is limited compared to results derived using the AFL method. This is consistent with other industry studies[82] highlighting the significant but localised contribution of grid-forming batteries for stable voltage waveform support. Based on this new information for the PACR, Transgrid modelled each grid-forming battery as contributing stable voltage waveform support exclusively to its nearest system strength node.

E.5 Hydro

Following the PADR, Transgrid engaged GHD as an independent expert to provide advice on the technical feasibility of NSW hydro units for system strength provision. This helped ensure outputs of the market

[80] AEMO, December 2024, 2024 Transition Plan for System Security
[81] Transgrid, 2024, Technical performance and power system modelling requirements for grid-forming BESS
[82] Electranet, 2025, Contribution of GFM BESS for System Strength | Feasibility Assessment

modelling were technically credible and considered highly likely to meet the need. GHD assessed hydro units offering system strength through:

- 'Re-dispatch' in generating or pumping mode (if applicable) representing an increase in generating hours on top of ordinary market dispatch;
- Operation of plant in synchronous condenser mode (if applicable); and
- Upgrade of plant to include synchronous condenser mode.

GHD assessed the available information for EOI solutions including information submitted by proponents and publicly available documents to inform inputs into Transgrid's market modelling. This included a review of costs, timeframes and feasibility of each solution. Outputs of this assessment were used to update modelling input assumptions such as capital costs, operating costs and earliest delivery dates.

GHD confirmed the technical and commercial feasibility of all hydro EOI projects. This includes solutions which require modifications to enable the unit to operate in synchronous condenser mode and re-dispatch of existing plant in generation or synchronous condenser mode (if available). GHD's view was that the operation of hydro units in synchronous condenser mode would not materially increase fixed or variable maintenance costs relative to operating in generation or pumping mode[83]. Additionally, GHD noted the significant potential for increased system strength provision by NSW hydro units, given their relatively low historical utilisation rates.

E.6 Gas

GHD also conducted a high-level assessment of the capacity for NSW gas units to provide system strength, beyond their typical operating hours. GHD noted concerns for projects in certain locations to access an adequate supply of gas due to the pipeline capacity supplying gas-powered generators. On advice of GHD, Transgrid implemented a limit on the daily fuel offtake for gas generators reliant on the Sydney to Newcastle gas pipeline. This constraint represents the limitations on the gas network and corresponding gas generation. This is in addition to AEMO's NEM-wide gas constraint which has been applied consistent with IASR assumptions.

Gas generation is the highest marginal cost solution. Therefore, this constraint does not enable alternative system strength solutions but allows Transgrid to more accurately identify system strength gaps in periods where there is unlikely to be sufficient gas supply, particularly in years prior to new synchronous solutions being deployed (such as synchronous condensers). GHD assessed that the solution of building additional infrastructure to increase gas supply, including gas storage or transmission lines, would be extremely costly and not practical as a solution for the purposes of this RIT-T.

GHD noted tightness in the current gas market and raised concerns that a significant re-dispatch of gas for system strength purposes could have flow on consequences for the gas market. However, this was considered out of scope for this RIT-T (and therefore was not modelled) due to complexity and uncertainty.

[83] Variable maintenance costs of hydro units are considered proportional to the number of start/stops the plant must undergo. For system strength provision, the unit will need to undergo the same number of start/stop sequences in gen/pump mode or synchronous condenser mode. Noting a switch from gen/pump mode to synchronous condenser does not require a start/stop.

E.7 Coal

Transgrid confirms that NSW coal units operating in generation mode to provide system strength is considered credible. However, Transgrid notes that under the 'Improving security frameworks for the energy transition' rule change [84], AEMO's operational enablement will be guided by principles specified in the rules. The enablement principles under NER 4.4A.4 include a system security service should be enabled as close as practicable to the relevant trading interval, and in any case, enabled no more than 12 hours ahead of the trading interval. This may limit the amount of ISF enablement that is possible from coal units, as coal units typically require more than 12 hours to start up from a cold state. This 12-hour limit has not been imposed within the PACR market modelling as it is not feasible within the current modelling framework; instead, it will be considered as part of Transgrid's contracting decisions.

[84] AEMC, 2024, Improving security frameworks for the energy transition rule change

Appendix F Estimating Net Market Benefits

For each option identified in the PACR, 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 specific categories of market benefit under the RIT-T that have been modelled as part of this PACR 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.[85]

While Section F.7, 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.

F.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 F.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 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.

F.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).

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

[85] 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, August 2020, *Regulatory Investment Test for Transmission*

Emissions Reduction (VER) should be determined.[86] The AER also published final guidance in May 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 annual VERs consistent with the MCE.[87] Transgrid note that this additional AER guidance is binding due to the transitional provisions stipulated in the Act.[88]

For the PACR, Transgrid has adopted the VERs as determined by the Energy Ministers. Specifically, the approach applied for the PACR 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 short run marginal cost 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 Energy Ministers' VER values for all portfolio options and sensitivities; and
- for the subsequent NPV assessment (using PLEXOS Short Term modelling) – the Energy Minister's published VER is used, ex-post, for all portfolio options and sensitivities (and, for the VER sensitivity, we have expanded this to investigate +/- 25% on the VER value consistent with the MCE guidance).[89] Applying VER ex-post means that emissions costs do not affect market dispatch decisions, but are incorporated in the costs and benefits assessment.

Transgrid has conducted sensitivity analysis with a reasonable margin to understand the potential impact that specific values of emissions reduction may have in this RIT-T.[90] Transgrid also 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.

F.3 Changes in involuntary load curtailment

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.

In this assessment Transgrid has not included 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

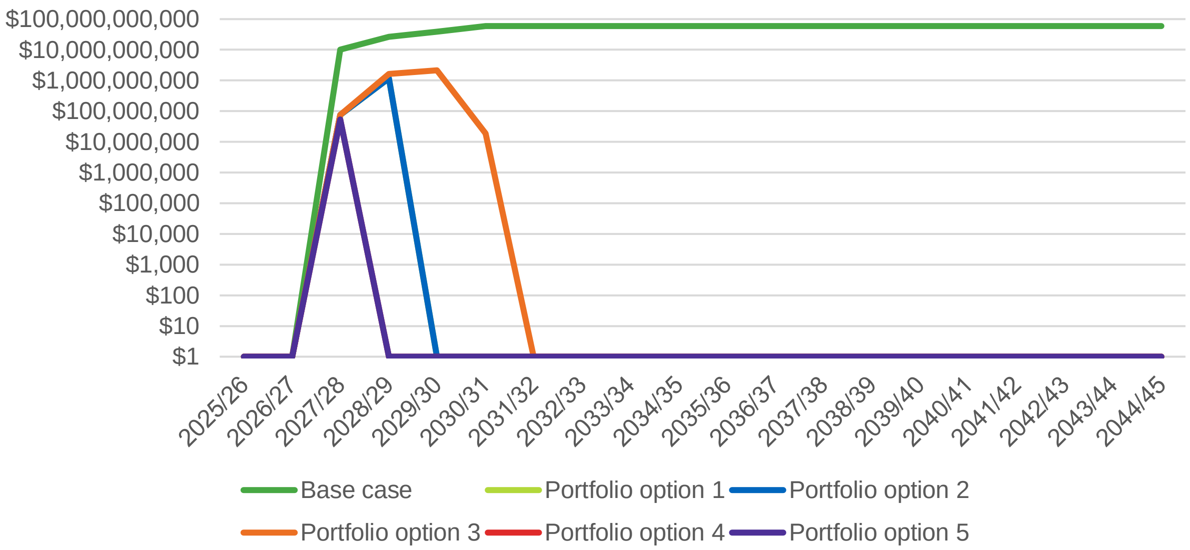
[86] AEMC, April 2024, MCE statement about the interim value of greenhouse gas emissions reduction
[87] AER, March 2024, *Valuing emissions reduction* - AER draft guidance
[88] AER, September 2023, AER guidance on amended National Energy Objectives Guidance Note
[89] AEMC, April 2024, MCE statement about the interim value of greenhouse gas emissions reduction
[90] AER, September 2023, Amended National Energy Objectives (Emissions Reduction) – Guidance Note - Explanatory Statement

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).

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 has only valued the *differences* in avoided unserved energy across the portfolio options. Transgrid explicitly removed all avoided unserved energy common to each of the portfolio 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 portfolio options would swamp the other benefit sources. Transgrid considers this is consistent with the approach adopted in other RIT-Ts, the Energy Networks Australia RIT-T Handbook and advice provided to the AER.[91]

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 48 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 48. Value of involuntary load curtailment under base case and portfolio options (undiscounted $2023/24)



The specific approach adopted to removing the common avoided unserved energy has been to only include the avoided unserved energy for each portfolio option over and above the worst performing portfolio option (i.e., portfolio option 3). This means that the NPV assessment in this PADR has zero avoided unserved for portfolio option 3, and a positive amount for the other portfolio options.

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

[91] Biggar, D., May 2017, An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the ‘Powering Sydney’s Future’ Program

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 purpose of this assessment.

F.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 FOM, VOM 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.

F.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.

F.6 Changes in network losses

The time-sequential market modelling has considered the change in network losses that may be expected to occur because 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 portfolio options is not considered material for the portfolio options considered in this PACR, 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.

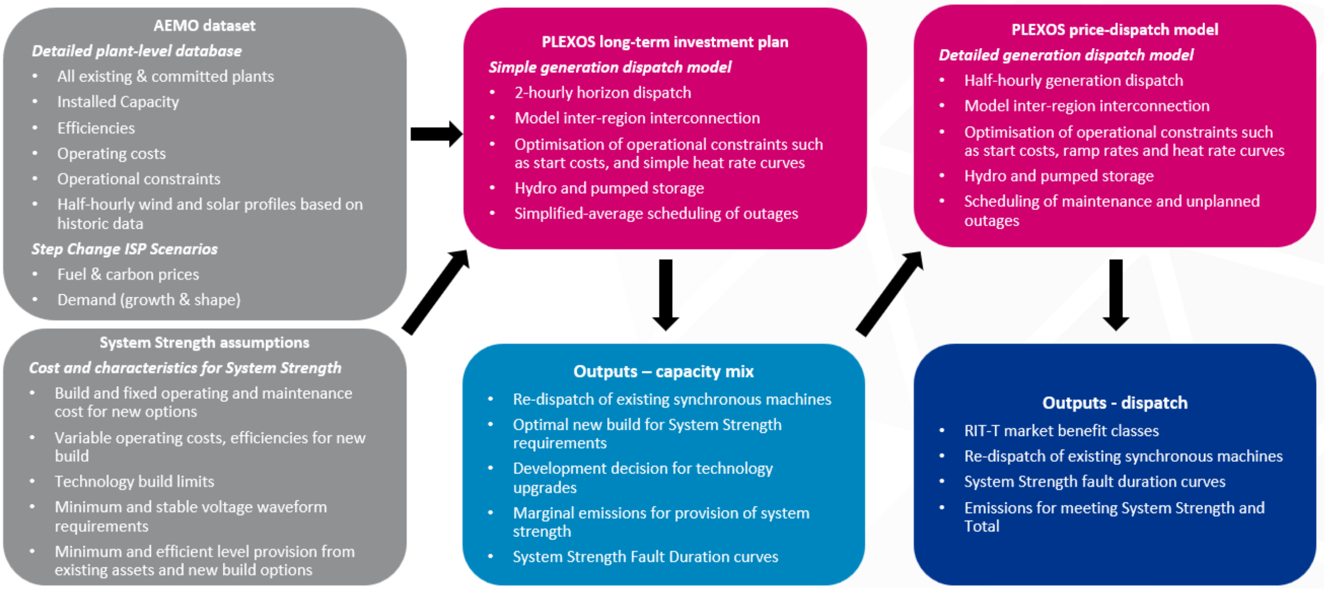
F.7 Market modelling has been used to estimate the wholesale market benefits

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 has undertaken detailed power system simulations to evaluate the performance of portfolio options 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 49. Summary of the market modelling processes undertaken



F.8 Inputs and assumptions adopted for market modelling

The modelling process uses the same market modelling software (PLEXOS) as AEMO and input assumptions aligned with AEMO's Final 2024 ISP Step change scenario, based on AEMO's 2023 IASR. Inputs from AEMO's Draft 2025 IASR, published in December 2024, were not opted to be used for the market modelling. The draft values had not been subject to stakeholder feedback by the time market modelling for the PACR commenced and regardless were not expected to materially change the outcomes of the RIT-T.

Where material market updates have emerged since the 2023 IASR and PACR modelling, these have been incorporated. Two primary updates have occurred including:

- Update of NSW coal closure schedule to reflect the delayed retirement of Eraring Power Station to August 2027. This is consistent with the Supplementary Report to the PADR published in October 2024 by Transgrid.
- Update of the IBR forecast to reflect the delayed delivery of the New England REZ transmission project. Although Transgrid is obligated to use the IBR forecast provided by AEMO in its System

Strength Report[92], this forecast has become out-of-date. This is in-line with guidance from the AER and AEMO.[93]

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, published alongside this report.

F.9 Competition benefits, option value and changes in ancillary service costs are not expected to be material

As the portfolio options considered in this PACR do not address network constraints between competing generators, and all credible portfolio 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 Appendix G). Moreover, 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 portfolio options, we consider that changes in FCAS costs are not likely to be materially different between portfolio 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 portfolio options). 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 portfolio options being considered.

F.10 General cost benefit analysis parameters adopted

The PACR 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 solutions 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 portfolio 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 solutions over the assessment period is appropriately captured, and that all solutions 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

[92] AEMO, System Security Planning

[93] AEMO, 16 December 2024, AER Efficient management of system strength framework – Guidance Note, stating "AEMO is supportive of SSSPs considering the latest available information and announcements to adjust these values for use in their system strength RIT-Ts between publications of the System Strength Report."

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 percent has been adopted as the central assumption for the NPV analysis presented in this PACR, consistent with AEMO's 2023 IASR[94] and draft 2025 IASR[95]. 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 has therefore tested the sensitivity of the results to a lower bound discount rate of 4.18% percent[96]. Transgrid has also adopted an upper bound discount rate of 10.5 percent (i.e., the upper bound in AEMO's latest Final IASR).

[94] AEMO, July 2023, Assumptions and Scenarios Report - Final report

[95] AEMO, December 2024, Assumptions and Scenarios Report - Draft report

[96] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Directlink) as of the date of this analysis, see: AER, April 2025, *Directlink – 2025-30 – Final decision – PTRM*

Appendix G – Modelling input assumptions

Transgrid has 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'.[97]

The other two ISP scenarios (i.e., the Progressive Change and Green Energy Exports scenarios) have not been used in the analysis. This approach is consistent with AER's guidance note on system strength [98].

Table 29 summarises the specific key input parameters that drive the portfolio formation and net present value assessment. The 2025 draft IASR was released in December 2024 (Stage 1) and January 2025 (Stage 2). As this IASR has not been finalised at the time of market modelling and the draft IASR did not show changes likely to materially impact this assessment, the PACR has used assumptions from the 2023 IASR consistent with the PADR.

Table 29. PACR modelling input assumptions

Key input parameters	Input Category	Source
Powering Australia	Federal policy	2023 IASR. Minimum 82% renewable share of total generation by 2029/30.
NSW Energy Infrastructure Roadmap Generation	State policy	2023 IASR. Minimum 33,600 GWh of eligible renewable generation by 2029/30.
NSW Energy Infrastructure Roadmap Storage	State policy	2023 IASR. 2000MW/1600MWh of eligible large-scale storage by 2029/30. Additional 1200MWh of eligible large-scale storage by 2033/34.
Tasmanian Renewable Energy Target (RET)	State policy	2023 IASR. Minimum 15,750GWh of renewable generation 2029/30 and 21,000GWh of renewable generation by 2039/40.
Victorian Offshore Wind Target	State policy	2023 IASR. Victorian offshore wind capacity to be 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.
Victorian Energy Storage Target	State policy	2023 IASR. Minimum 2.6 GW of eligible large-scale storage by 2030 and 6.3GW of eligible large-scale storage by 2035.
Victorian RET	State policy	2023 IASR. Minimum 40% renewable energy generation as a percentage of total Victorian generation by 2025, 65% by 2030, and 95% by 2035.
Queensland RET	State policy	2023 IASR. Minimum 50% renewable energy generation as a percentage of total QLD underlying consumption by 2030, 70% by 2032, and 80% by 2035

[97] AEMO, July 2023, Assumptions and Scenarios Report
[98] AER, December 2024, Efficient Management of System Strength Framework – Guidance note

Key input parameters	Input Category	Source
Cumulative NEM-wide and state-based carbon budgets	Long-term model carbon constraint	2023 IASR (Step Change scenario)
Group REZ limits	Network expansion	2023 IASR
Flow path augmentations	Network expansion	2023 IASR
Interconnector developments	Network expansion	2023 IASR
Transmission development pathway	Network expansion	Final 2024 ISP Optimal Development Pathway (ODP) with updates to reflect latest available proponent advised timings, see market modelling report
Renewable energy zone representation	Network expansion	2023 IASR
Underlying consumption	Demand	Final 2023 NEM Electricity Statement of Opportunities (Step Change Scenario).
Demand side participation	Demand	2023 IASR (Step Change Scenario)
Rooftop PV	Capacity mix	AEMO Final ISP 2024 (Step Change Scenario).
New entrant build limits	Capacity mix	2023 IASR
Generator energy limits	Capacity mix	2023 IASR
Fixed date asset retirement	Capacity mix	AEMO Final ISP 2024 (Step Change Scenario). Exception of Eraring Power Station which was updated to reflect delayed retirement to August 2027.
Resource limits	Capacity mix	2023 IASR
Capacity factors	Capacity mix	2023 IASR
Technical parameters of generation & storage (existing and new entrant)	Capacity mix	2023 IASR. Exception of gas variable operating and maintenance costs, see market modelling report.
Maintenance rates	Capacity mix	2023 IASR
Generator reliability settings	Capacity mix	2023 IASR. Exceptions applied based on proponent information, see market modelling report.
Hydroelectric storage inflows	Capacity mix	2023 IASR
Capital costs	Costs	2023 IASR (Step Change Scenario)
Weighted average cost of capital, all new generation and transmission	Costs	2023 IASR (Central assumption)
Coal fuel cost	Fuel costs	2023 IASR (Step Change Scenario)
Gas fuel cost	Fuel costs	2023 IASR (Step Change Scenario)
Value of emissions	Other	AER Final Guidance Note May 2024
Committed and anticipated projects list	Capacity mix	AEMO NEM Generator Information (October 2024)
Power system constraints – synchronous generating units	Capacity mix	2023 IASR (Step Change scenario) for QLD, VIC and SA.

Appendix H – Changes to portfolio options since the PADR

Portfolio options have evolved since the PADR. Changes made are shown in Table 30.

Table 30. Evolution of portfolio options since the PADR

PACR Portfolio Option	Change since the PADR
Portfolio option 1	This is the same portfolio option as Portfolio Option 1 of the PADR. There have been refinements to the underlying assumptions including the timing of synchronous condensers which have led to small changes in the composition of the portfolio since the PADR.
Portfolio option 2	This is a new portfolio option since the PADR. Adding additional robustness ('enhanced' portfolio) by bringing forward synchronous condensers was introduced and consulted on in the PADR Supplementary Report Sensitivity 3.
Portfolio option 3	This is the same portfolio option as Portfolio Option 1 of the PADR except with an assumed later available timing of synchronous condensers.
Portfolio option 4	This is the same portfolio option as Portfolio Option 2 of the PADR. Underlying assumptions have been refined which have led to small changes in the composition of the portfolio since the PADR.
Portfolio option 5	This is a new portfolio option since the PADR which reflects a slight modification to Portfolio Option 2 of the PADR enabling additional acceleration.
Portfolio options removed since the PADR	Portfolio Option 3 of the PADR was found to be technically infeasible and has been removed. Portfolio Option 4 of the PADR has been removed. An additional gas constraint has been implemented in the PACR.

Appendix I – Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PACR 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.[99]

> *"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[100], 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 portfolio option.

We have estimated the resulting situation where, dependent upon it being a minimum or efficient level gap, load is shed and/or renewable generation is constrained as part of the base case in the PACR 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 F.3).

[99] AER, October 2023, Regulatory Investment Test for Transmission Application Guidelines

[100] *The Energy Networks Australia RIT-T Economic Assessment Handbook suggests where the base case for a reliability corrective action is not considered a viable option (as is the case in this RIT-T), the RIT-T consultation documentation should acknowledge that the base case is not considered a credible option in itself, and would never be pursued by the TNSP, but has been formulated consistent with the NER and the AER guidelines as a means of comparing credible option. The AER RIT-T guidelines acknowledge this may be the case on page 23.*

Appendix J – NPV impacts of constrained renewables in South West REZ

Transgrid has identified that one network synchronous condenser at Dinawan is part of all portfolio options, through an out-of-model assessment of the efficient level requirements using PSCAD. PSCAD studies showed that a stable voltage waveform could not be maintained without new system strength solutions, which wasn't captured during the portfolio optimisation process (due to Dinawan being electrically far from the Darlington Point node).

As the efficient level gap was not captured in the portfolio optimisation process, the benefits of the Dinawan synchronous condenser are also not captured despite its CAPEX and OPEX being included in the NPV analysis. As such, Transgrid has used an out-of-model assessment to incorporate the additional benefits of the Dinawan synchronous condenser in the NPV analysis under all portfolio options.

The Dinawan synchronous condenser is required purely to meet stable voltage waveform requirements and as such, the primary driver of net market benefits is by facilitating renewable generation as the lowest cost form of electricity. Transgrid has assessed using latest available information the amount and type of renewable generation likely to be constrained in each portfolio option without the Dinawan synchronous condenser in place (where its delivery timing varies in each portfolio option). Part of this assessment included considering the ability for hydro re-dispatch to be increased to meet this need, based on market modelling results.

Using renewable generation traces and generator short run marginal costs derived from the 2024 Integrated System Plan, Transgrid estimated the economic cost of additional generation that would be required from other sources (coal, gas, hydro and variable renewable energy) to replace the generation constrained in the South West REZ (prior to the arrival of the synchronous condenser).

These additional market benefits were incorporated in the NPV assessment. The magnitude of these additional market benefits was not significant (for example the NPV of portfolio option 1 increased by 0.9% and by 1.2% for portfolio option 5), however this supported a more robust assessment of the costs and benefits of the portfolio of system strength solutions.