Meeting system strength requirements in NSW

Baringa Market Modelling Report

For Transgrid's Project Assessment Conclusions Report (PACR)

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Contact

Dr Ian McDonnell (ian.mcdonnell@baringa.com)

Dr Bradley Steel (bradley.steel@baringa.com)

Sean Findlay (sean.findlay@baringa.com)

Jacob Masseurs (jacob.masseurs@baringa.com)

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Executive summary

As NSW's System Strength Service Provider (SSSP), Transgrid is responsible for ensuring sufficient system strength services are available to maintain the stability of the NSW power system. The expected retirement of NSW's coal generators and the growth in inverter-based resources (IBRs) is driving an urgent need for new system strength capacity.

Baringa has provided market modelling services to support Transgrid in identifying the optimal combination of network and non-network solutions available to maintain adequate system strength in NSW, as part of the Project Assessment Conclusions Report (PACR), which is the third stage in the Regulatory Investment Test for Transmission (RIT-T) process. This RIT-T is applied to potential solutions to meet Transgrid's National Electricity Rule (NER) obligations, specifically to:

- address a system strength shortfall in the transmission network at Newcastle and Sydney West nodes that is forecast to arise from 2027-28; and
- deliver system strength services to the NSW power system to meet standards set by the Australian Energy Market Operator (AEMO) from 2 December 2025, including for the safe and secure operation of the power system ('minimum level') and to facilitate the stable voltage waveform of new inverter-based resources ('efficient level').

This report is supplementary to the PACR published by Transgrid. It describes the market modelling methodologies (including both Portfolio Option optimisation and modelling of the RIT-T energy market benefit classes), key modelling assumptions and the input data sources which underpin this exercise.

A novel modelling methodology was developed to comprehensively capture the complexities of co-optimising system strength and energy market outcomes, where no one solution alone could meet the need and where solutions must be co-optimised across six system strength 'nodes' in NSW and at the connection points of all future IBRs. The modelling approach builds upon that used in the Project Assessment Draft Report (PADR) published in June 2024 and was the first published modelling approach in Australia to co-optimise energy market outcomes with system strength requirements. The approach follows the RIT-T guidelines published by the Australian Energy Regulator (AER). The approach was used to form optimal 'portfolios of solutions' to meet system strength requirements and maximise net economic benefits to participants in the National Electricity Market (NEM).

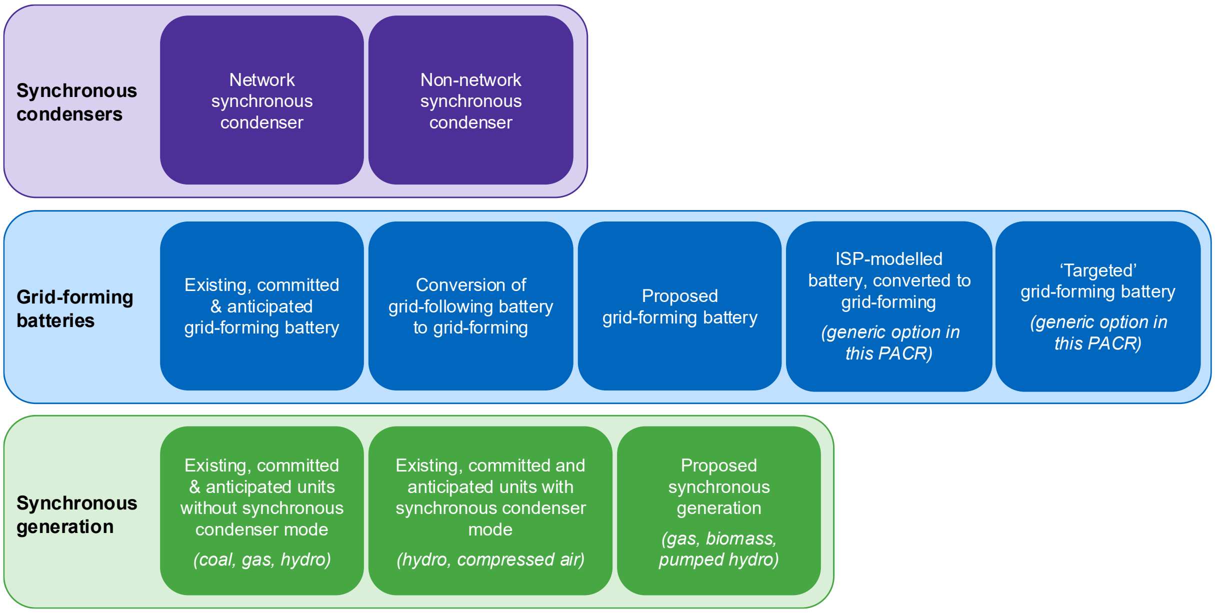
The approach combines electricity market modelling with power system modelling to optimally construct and analyse credible portfolios of both network and non-network system strength solutions to meet Transgrid's system strength obligations. This approach involves:

- Development of the generation and storage capacity outlook of the NEM, based on an equivalent scenario to AEMO's Final 2024 Integrated System Plan (ISP) Step Change scenario based on latest available information at the time of modelling.

- Construction of system strength Portfolio Options using long-term capacity expansion and market dispatch modelling that optimises investment in new system strength solutions and re-dispatch[1] of existing plant to meet Transgrid's system strength obligations.
- Validation of the robustness of Portfolio Options to meet the system strength need through detailed power systems modelling.
- Detailed market dispatch modelling to determine market outcomes under each Portfolio Option.
- Evaluation of the economic costs and benefits of each Portfolio Option, under the RIT-T markets benefits classes.

To form optimal portfolios of system strength solutions, this market modelling approach considered more than 100 individual network and non-network system strength solutions, leading to more than 2^{100} possible combinations. A summary of the individual system strength solutions considered in this modelling process is shown in Figure 1 below.

Figure 1. Categories of network and non-network solutions considered

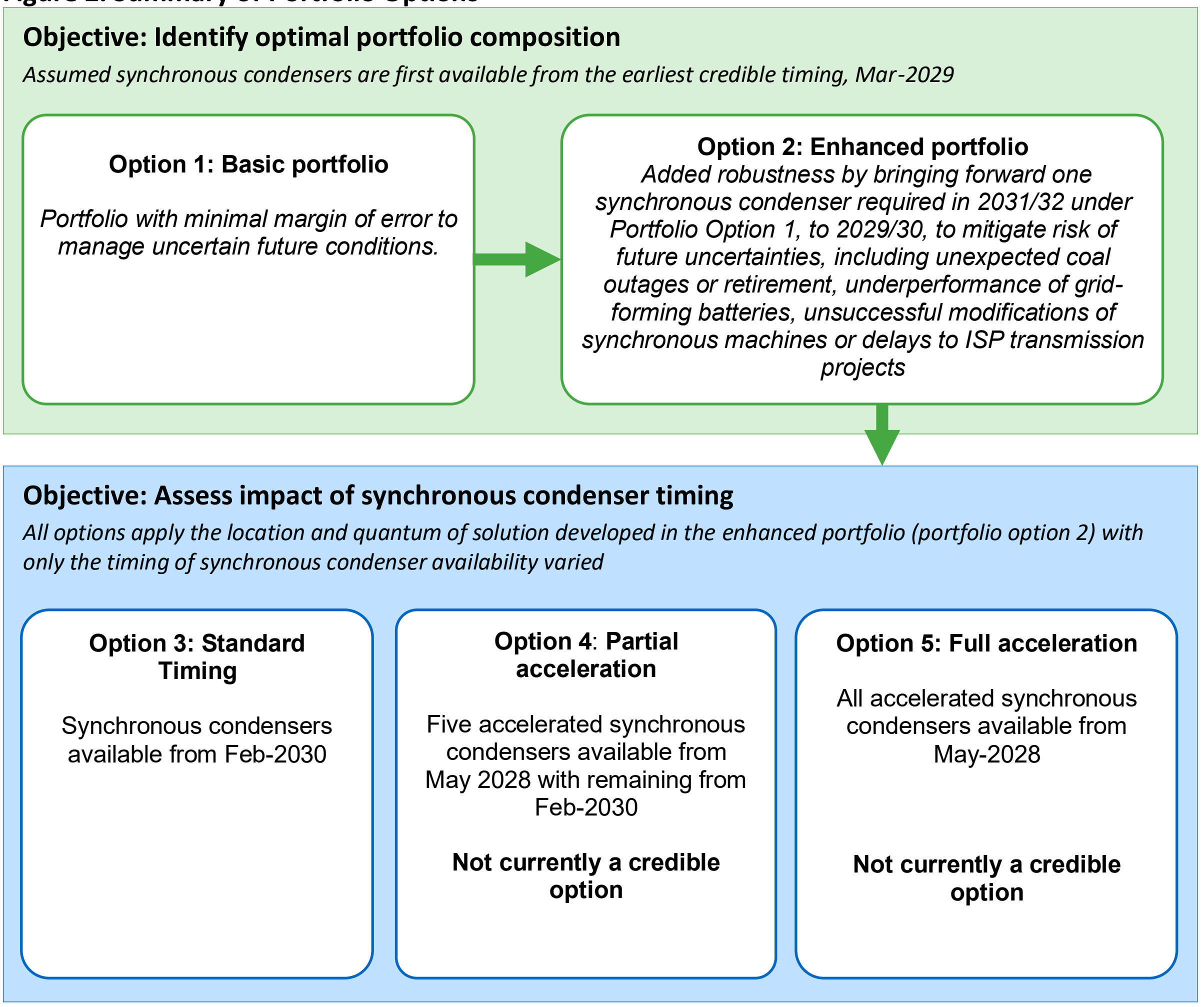


The PACR portfolio optimisation process considered the above network and non-network solutions using specialist market modelling and power system analysis software. The objective was to identify an optimal portfolio of system strength solutions (termed 'Portfolio Option') which meet Transgrid's requirements and provide the greatest net benefits to the energy market. Different Portfolio Options were then created by varying the earliest timing assumption of new build synchronous condensers.

An economic cost benefit assessment for each Portfolio Option was undertaken and compared against a business-as-usual Base Case.

[1] Where re-dispatch is the change in operation of synchronous generators required to satisfy system strength constraints at least-cost relative to typical energy market dispatch.

Figure 2. Summary of Portfolio Options



At this stage, only Portfolio Option 1, Portfolio Option 2 and Portfolio Option 3 are considered credible Portfolio Options as Portfolio Options 4 and 5 assume synchronous condensers are available earlier than Transgrid consider credible. March 2029 (for Portfolio Option 1 and 2) and February 2030 (for Portfolio Option 3) represents a range of credible timing the first synchronous condenser can be deployed, following the normal regulatory and procurement processes. While Portfolio Option 2 assumes the earliest credible timing, March 2029, its timing is considered optimistic, and it is more likely that the standard timing of February 2030 would occur (as in Portfolio Option 3).

Insights from our PACR market modelling show that if ‘accelerated’ synchronous condensers were proven to be credible, there would be significant additional market benefits. The acceleration of synchronous condensers requires procurement ahead of the completion of the regulatory process.

Table 1. Composition of 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 1,050 MVA 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 1,050 MVA fault current)									
Portfolio 1	–	–	–	–	–	–	6	8	8
Portfolio 2	–	–	–	–	–	–	5	7	7
Portfolio 3	–	–	–	–	–	–	5	7	7
Portfolio 4	–	–	–	–	–	–	5	7	7
Portfolio 5	–	–	–	–	–	–	5	7	7
Hunter-Central Coast REZ system strength solutions									
Common across all portfolios	-	-	Note 2						
Upgrades to synchronous machine to allow synchronous condenser mode (existing and new units) – cumulative capacity (MW)									
Common across all portfolios	50	50	300	650	650	650	650	650	650
Grid-forming BESS – cumulative capacity (MW)									
Common across 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 <950 MVA 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 by Transgrid 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 for this REZ through the procurement process (which will be contracted as a non-network option).									

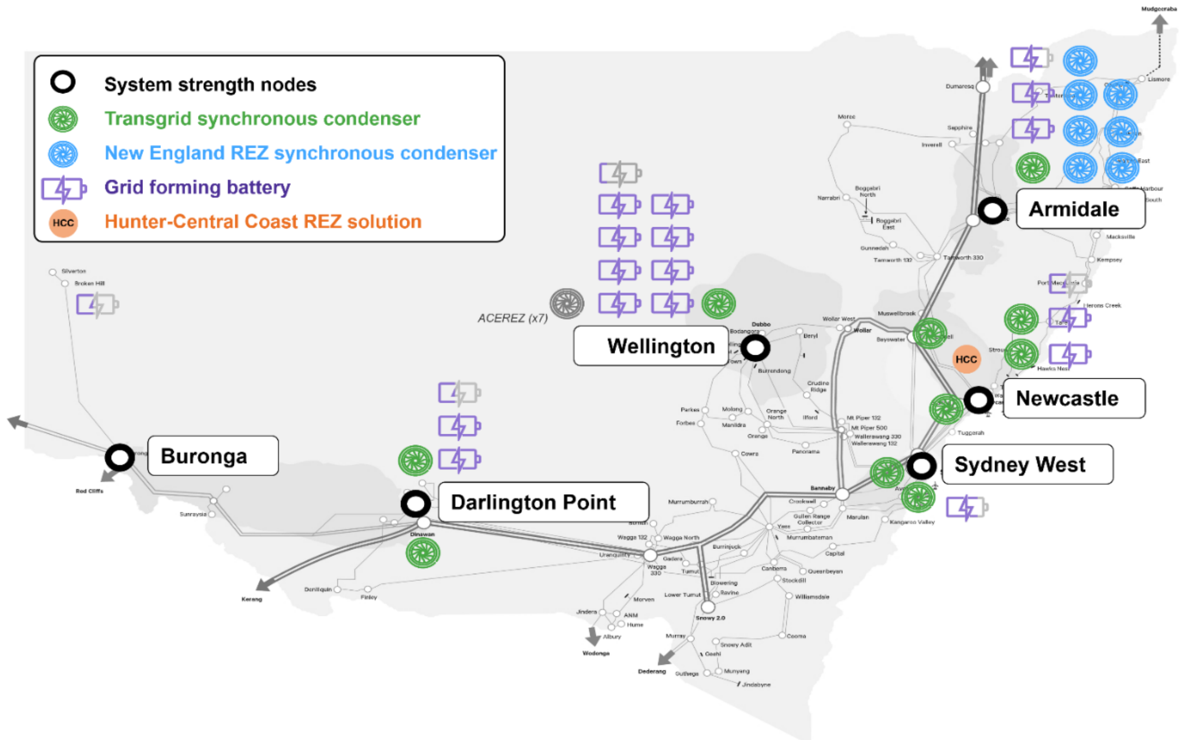
The outcome of the modelling shows that all Portfolio Options contain a blend of non-network system strength solutions (including coal, hydro, gas and grid-forming batteries) and network system strength solutions (synchronous condensers).

Transgrid has identified the enhanced portfolio (Portfolio Option 2) as the preferred Portfolio Option. This is comprised of:

- Ten network 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;
- 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.

A map of NSW which indicates the type, size, timing, and location of new system strength assets selected in Portfolio Option 2 is provided in Figure 3 below.

Figure 3. Indicative map of new-build system strength solutions in Portfolio Option 2[2]



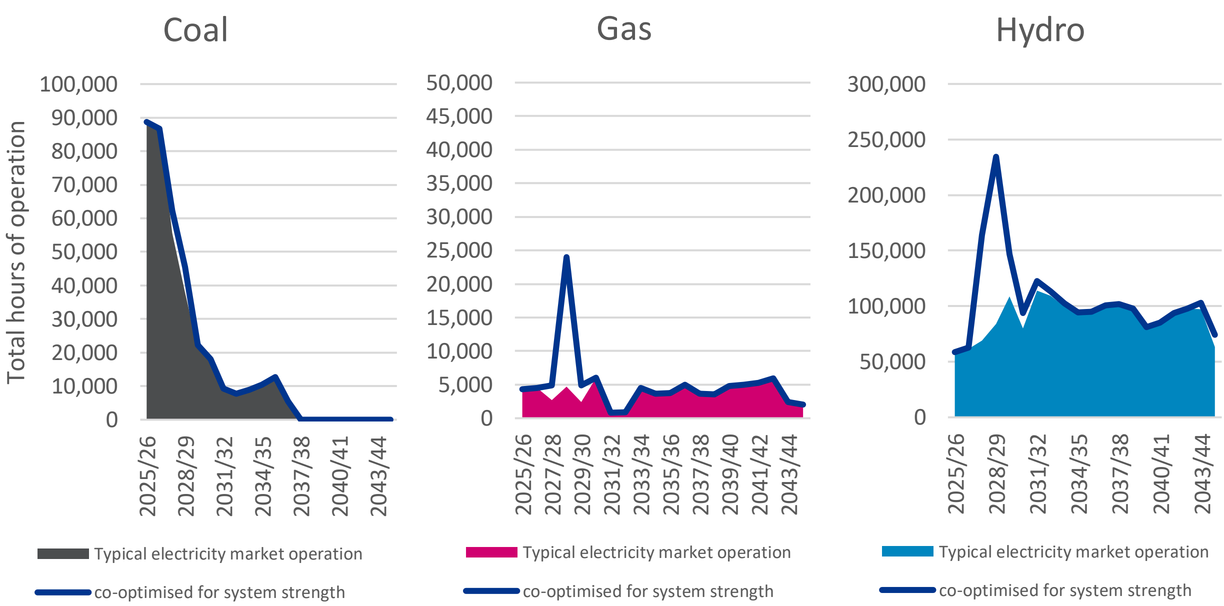
Note: This figure does not show the re-dispatch of existing machines, which are also included in this Portfolio Option.

These new build system strength solutions are coupled with the additional dispatch of existing and committed synchronous machines to meet system strength obligations (termed 're-dispatch'). Figure 4 demonstrates the change in operation of synchronous generators in Portfolio Option 2 when co-

2 Grid-forming battery icon represents the equivalent contribution to the efficient level of system strength as one synchronous condenser

optimised to meet system strength requirements relative to energy-only market dispatch (which assumes there are no system strength obligations[3]).

Figure 4. Re-dispatch of coal, gas and hydro in operating hours to meet system strength requirements in the enhanced portfolio



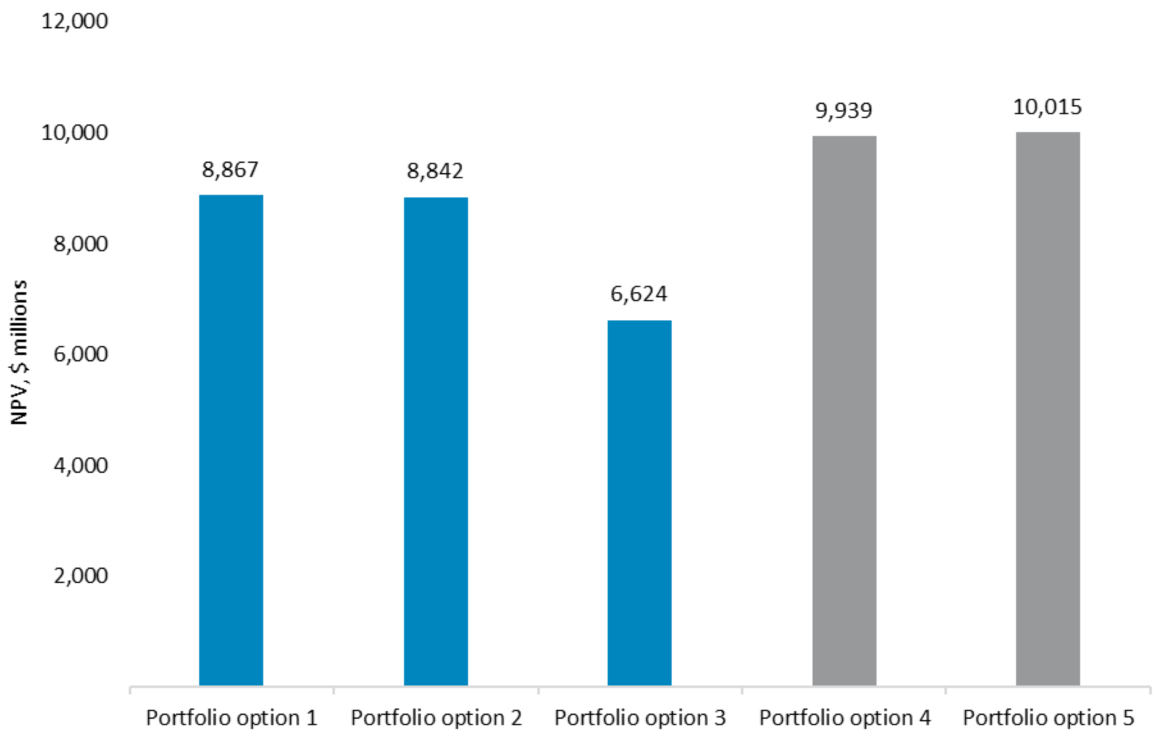
The combination of new build solutions, and modified dispatch of existing and committed synchronous machines, provides a pathway to address system strength needs where feasible whilst minimising costs to the NEM.

Figure 5 below 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[4] $6.6 billion in net benefits, in present value terms. The three credible portfolio options are distinguishable below in blue with the two non-credible portfolio options in grey. The non-credible portfolio options model an ‘accelerated’ synchronous condenser deployment which demonstrates greater additional benefits if proven to be credible. The acceleration of synchronous condensers requires procurement ahead of the completion of the regulatory process.

[3] As described in Section 2.5.1

[4] 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. If this unserved energy is added to the analysis, the expected net benefit of all portfolio options would be significantly greater.

Figure 5. Net present values for portfolio options 1-5, blue indicating credible portfolio options and grey indicating not yet credible portfolio options



Contents

1 Introduction

1.1 Context

As the System Strength Service Provider (SSSP) for the New South Wales (NSW) power system, Transgrid must proactively ensure there is sufficient system strength available, to ensure the safe and secure operation of the power system ('minimum' level) and to facilitate the stable voltage waveform ('efficient' level) of new inverter-bases resources (IBR).

Transgrid is applying the Regulatory Investment Test for Transmission (RIT-T) to Portfolio Options that meet system strength requirements in the NSW power system. This RIT-T examines network and non-network solutions to ensure compliance with system strength requirements and to provide the greatest net market benefit. 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.

Baringa has provided market modelling services to support Transgrid's 'Meeting system strength requirements in NSW' RIT-T Project Assessment Conclusions Report (PACR) assessment. Baringa assessed more than 100 individual network and non-network system strength solutions, developed a portfolio optimisation approach to form credible portfolios of individual system strength solutions, and undertook market modelling to inform the market benefit assessment of each portfolio.

This builds upon and refines the modelling approach and assumptions in Transgrid's Project Assessment Draft Report (PADR), detailed in Baringa's supplementary PADR market modelling report[5].

1.2 Purpose of this report

This report is supplementary to the PACR[6] published by Transgrid. It describes the market modelling methodologies (portfolio optimisation and modelling of market benefits), key modelling assumptions and the input data sources which underpin this exercise to:

- form optimal portfolios of system strength solutions that maximise net economic benefits and meet system strength requirements where feasible;
- do so under several sets of underlying assumptions that define different possibilities around the timing of system strength solutions, to test the impact of these assumptions and create different Portfolio Options; and
- assess the market benefits of each Portfolio Option relative to a business-as-usual Base Case.

[5] Baringa, Meeting System Strength Requirements in NSW – Baringa Market Modelling Report, June 2024. Available at: https://www.transgrid.com.au/media/wphjea0f/2406-baringa_meeting-system-strength-requirements-in-nsw-padr-modelling-report.pdf

[6] Transgrid, Meeting system strength requirements in NSW – RIT-T Project Assessments Conclusions Report (PACR), July 2025. Available at: https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

Baringa and Transgrid worked extensively together to incorporate Transgrid's detailed power system studies and engineering expertise into both the market modelling methodology and RIT-T market benefits assessments. This market modelling methodology report reflects the collaborative nature of this work and explicitly uses 'pop-out' boxes to highlight the technical methodologies developed and power systems analysis conducted by Transgrid. These sections are distinguishable by blue boxes and can be found in Section 2 (modelling methodology), Section 2.5.6 (input assumptions and scenarios) and Section 4 (system strength representation).

As per the Australian Energy Regulator (AER) RIT-T guidelines, Baringa adopted inputs and assumptions predominantly based on AEMO's 2024 Final Integrated System Plan (ISP), released in June 2024, with updates to reflect more recent information where applicable.

When assessing the benefits of different Portfolio Options, the following classes of market benefits were considered material and have been included in the market benefit assessment:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in Australia's greenhouse gas emissions
- changes in costs for parties, other than the RIT-T proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs
- difference in the timing of expenditure
- changes in voluntary load curtailment
- changes in involuntary load curtailment via system strength gaps

Each category of market benefits has been calculated for the twenty-year period from 2025/26 to 2044/45. All monetary values are presented in 30 June 2024 real dollars (2023/2024), and the net present value of market benefits have been discounted to 1 July 2025, with the use of a 7% pre-tax real discount rate (except where otherwise specified), consistent with the discount rate to be applied by AEMO in the Final 2024 ISP.

This report is structured as follows:

- Section 2 provides an overview of the market modelling methodology and the approach to forming credible portfolios of system strength solutions.
- Section 3 outlines the key inputs and assumptions underpinning the market modelling.
- Section 4 summarises the construction and representation of the system strength requirements in the modelling.
- Section 5 provides an overview of the Portfolio Options design.
- Section 6 presents detailed results and outcomes of the market modelling, extending beyond those presented in the PACR.
- Section 7 explores the detailed market benefit outcomes of the Base Case and each Portfolio Option relative to Portfolio Option 2 (the preferred credible Portfolio Option).

2 Modelling methodology

This section describes the approach and methodology developed to construct credible portfolios of system strength solutions, and to undertake the market modelling and market benefits assessment.

Historically, the system strength provided as a by-product of synchronous generation to meet electricity demand has been sufficient to ensure the safe and secure operation of the NSW power system. However, the forecast retirement of NSW coal generators in the coming decade (80% retiring by capacity) and the growth in IBRs will mean that system strength requirements will at times exceed the system strength supplied by the market dispatch of synchronous generation.

The solutions to satisfy the additional system strength required include the 're-dispatch' of synchronous generators and investment in new sources of system strength, such as synchronous condensers and grid-forming batteries.

Our market modelling approach is designed to:

- Form credible portfolios of individual system strength solutions, which minimise total system costs whilst meeting system strength constraints and other network and operational constraints, through solving a long-term capacity expansion problem.
- Co-optimise the dispatch of the National Electricity Market (NEM) to maximise the present value net economic benefits to the electricity system whilst simultaneously meeting system wide electricity demand and system strength requirements, for each of the Portfolio Options.

Project costs under each of the material market benefit classes to undertake a cost-benefit analysis of each Portfolio Option relative to the Base Case following the RIT-T guidelines published by the AER[7].

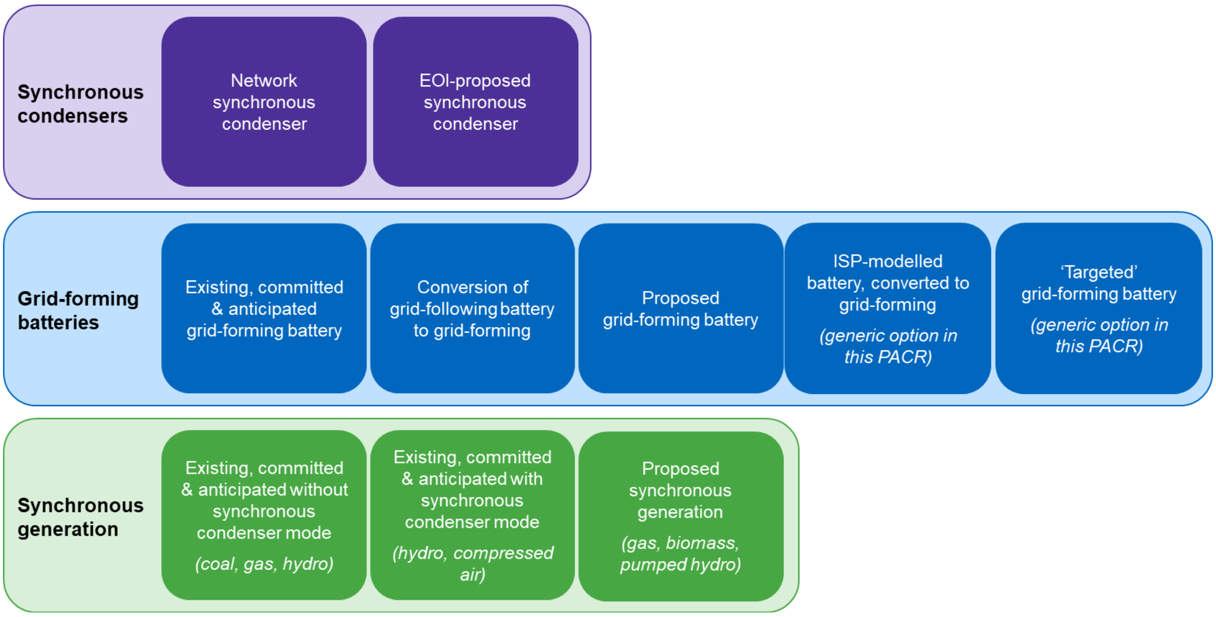
Section 2.1 briefly describes the candidate network and non-network solutions considered in the formulation of the system strength portfolios. Section 2.2 describes the portfolio optimisation process that selects which solutions are in the optimal portfolios of solutions. Section 2.5 describes the market dispatch modelling to assess the net economic benefits of each portfolio option.

2.1 Candidate system strength solutions

Transgrid's system strength expressions of interest (EOI) process resulted in non-network option submissions from 30 parties, covering over 60 individual potential solutions. Transgrid also developed 46 potential network solutions to meet the need, including synchronous condensers and grid-forming battery energy storage system (BESS). As such, in forming system strength portfolios, more than 2^{100} possible combinations of potential network and non-network solutions were considered. A summary of the types of system strength solutions considered is shown in Figure 6.

[7] AER, *Regulatory investment test for* transmission – Application *Guidelines,* July 2023. Available at: https://www.aer.gov.au/system/files/AER%20-%20RIT-T%20guidelines%20-%20draft%20amendments%20-%2028%20July%202023.pdf

Figure 6. Overview of available system strength solutions



All system strength solutions considered credible were included as potential solutions within the Portfolio Options formation. Further detail on the assumptions made for each of the candidate system strength solutions are provided in Section 3.3.

2.2 Overview of the modelling approach

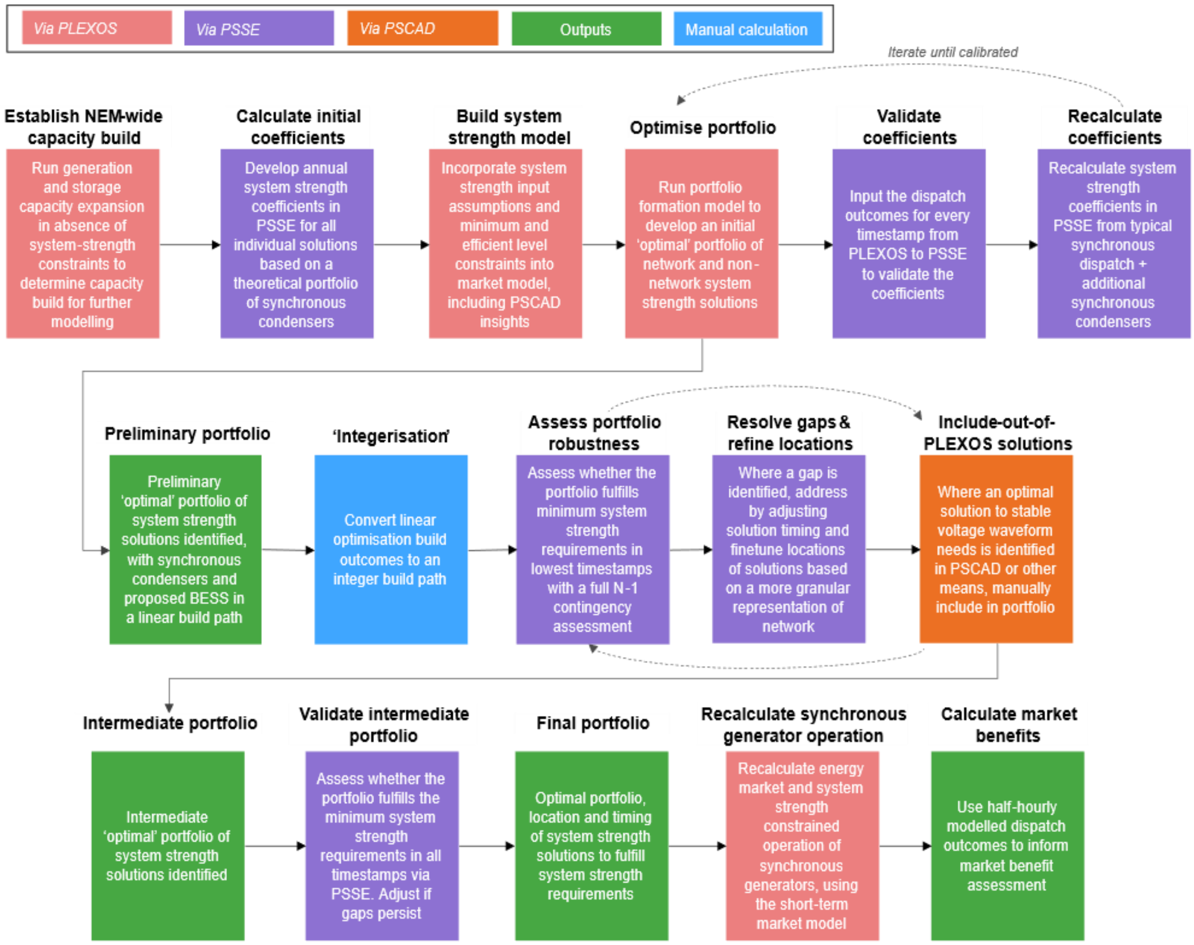
Baringa and Transgrid developed a modelling methodology that co-optimises system strength and energy market outcomes, where no one solution alone could meet the need, and solutions must be co-optimised across six system strength 'nodes' in NSW and at the connection points of forecasted IBRs. To capture the dynamic characteristics of system strength, this methodology involves an iterative approach between market modelling (using PLEXOS[8]) undertaken by Baringa, and power system modelling (PSS®E[9] and PSCAD™) undertaken by Transgrid, to form, refine, validate and rank portfolios of system strength solutions.

Figure 7 provides a high-level overview of the modelling process, with a brief description provided below.

[8] PLEXOS, energy market simulation software developed by Energy Exemplar

[9] PSS®E , Siemens proprietary software for modelling and analysing transmission power systems

Figure 7. Overview of the modelling approach for this RIT-T



Baringa first optimises the least-cost generation and storage dispatch and capacity development plan for the NEM, associated with the input assumptions generally derived from the Step Chage scenario under AEMO's 2024 Final Integrated System Plan, with more up-to-date and relevant market information considered where available. This development plan represents the least-cost development pathway in the absence of system strength obligations. This development plan is used to:

1. Inform the system strength requirements following the approach AEMO uses to determine system strength obligations
2. Determine the generation and storage capacity pathway to meet electricity demand at least-cost in the absence of system strength constraints, to which potential new-build system strength solutions would be additional to

Transgrid then conducts PSS®E fault level studies to capture fault level contributions ("coefficients") of each system strength solution to each system strength node (varying annually, and for some synchronous generators the coefficients vary based on the specific combination of other machines online at the same time). Further detail on the associated technical detail and methodology is provided throughout the report in Sections 2.4.4, 4.1.1, and 4.1.3.

Transgrid's system strength obligations are incorporated into the PLEXOS model using a set of minimum and efficient level constraints as defined in Sections 4.2.1 and Section 4.2.2 respectively. The system strength coefficients are applied to each solution to determine their contribution towards meeting the system strength constraints at each system strength node.

Baringa then undertakes system strength portfolio optimisation, by co-optimising the least-cost generation and storage dispatch and system strength solution development plan for NSW. This approach, using the Long--Term Plan phase in PLEXOS is outlined in Section 2.4.3 and solving a Mixed-Integer Linear Programming (MILP) model to co-optimise unit commitment and capacity expansion with respect to electricity demand and Transgrid's system strength obligations. This process ensures sufficient system strength provision across all NSW system strength nodes to meet both the minimum and efficient level requirements in each time interval, where feasible.

An iterative process to validate and refine system strength coefficients for each existing and potential system strength solution then follows between PLEXOS and PSS®E. System strength coefficients are calibrated via recalculation in PSS®E based on the PLEXOS dispatch outcomes for every two-hour interval. Once the coefficients used in PLEXOS and those calculated in PSS®E converge, a final set of system strength coefficients are used to identify the preliminary portfolio of system strength solutions through the Baringa portfolio optimisation model. Further detail on this process is provided in Section 2.4.4.

An 'integerisation' step is required to transform the linear build path (i.e. partial build of solutions) output from the portfolio optimisations step into a discrete set of solutions. This is supported by analysis of fault current contribution factors and with PSS®E validation. More detail is provided in Section 2.4.5.

The next stage in the process is to validate the portfolio in PSS®E and PSCAD, to ensure that the portfolio of system strength solutions identified by Baringa's portfolio optimisation model is robust and able to meet the system strength requirements. Where system strength gaps are identified, system strength solutions are adjusted or introduced to resolve modelled gaps. This process is discussed in more detail in Section 2.4.5.

To confirm that the 'integerised' build path outputs fulfil the identified system strength need, Transgrid conducted further validation studies for each portfolio in PSS®E considering N-1 contingency assessment and specific critical planned outages. This tested for system strength gaps in each of the Portfolio Options utilising market dispatch outcomes.

Transgrid fine-tuned the locations of the proposed synchronous condensers, to place them in 'optimal' and feasible locations within the transmission network. This fine-tuning of locations considered PSS®E-identified system strength gaps, each location's capacity for hosting synchronous condensers and the need for synchronous condensers within Renewable Energy Zones (REZs). Where relocating synchronous condensers was insufficient to resolve system strength gaps, the timing of new entry solutions was adjusted to ensure all system strength requirements were met. See Section 2.4.6 for more detail.

Further validation was undertaken in PSCAD™ to validate the portfolio of system strength solutions in meeting the efficient level requirement of regions where high IBR uptake is forecast over the next five years (such as South West REZ and Hunter-Central Coast REZ). This PSCAD™ analysis used a full network topology including geographically dispersed IBR locations. Where efficient level system strength gaps were identified, system strength solutions were adjusted (or introduced in one case) to resolve modelled gaps.

Finally, Baringa undertakes short-term dispatch market modelling including the Portfolio Options, solving a time-sequential market dispatch Mixed-Integer Linear Programming (MILP) problems to determine the least-cost dispatch of the NEM to meet both electricity demand and system strength requirements in NSW where feasible. The outcomes of the market dispatch modelling are subsequently used in the calculation of market benefits as described in Section 6.

The remainder of this section provides more detail on each stage of the modelling approach described above.

2.3 Establish NEM-wide capacity development pathway

Baringa optimised the least-cost generation and storage dispatch and capacity development plan for the NEM, associated with the input assumptions based on the Step Chage scenario under AEMO's 2024 Final Integrated System Plan (ISP), with more up-to-date and relevant market information considered where available. Further detail on the input assumptions is provided in Section 2.5.6.

This model (which did not yet include system strength constraints) was used to perform long-term generation and storage capacity expansion optimisation of the NEM, to determine the capacity development pathway to be used in subsequent modelling. This modelling process seeks to minimise generation production costs alongside capital expenditure (capex) on generation and storage assets, whilst ensuring there is sufficient supply to reliably meet demand, respect physical limitations of the transmission system, meet legislated and publicly committed renewable energy targets and carbon budgets, and respect energy and technical limitations on energy resources.

This optimal capacity development pathway for meeting future energy market requirements was determined in the absence of system strength requirements. The resulting generation and storage capacity development pathway formed an exogenous input for the subsequent system strength portfolio optimisation process. This two-staged approach ensures that system strength solutions built in the following stages are built to meet Transgrid's system strength obligations, as the least-cost, NEM-wide capacity expansion solution to meet future electricity demand in the absence of system strength constraints.

2.4 Portfolio optimisation process

The number of individual network and non-network solutions assessed in this RIT-T meant that billions of potential individual solution combinations had to be considered and co-optimised considering the system strength requirements across the six system strength nodes in NSW and at the forecast point of connection of future IBRs. This, combined with the fact that system strength contributions are dynamic and non-linear and that individual contributions depend on which other units are operating at the same time, necessitated the development of a portfolio optimisation process for considering and forming 'Portfolio Options'.

This sub-section outlines the key features of the portfolio optimisation approach applied to develop portfolios of existing and new non-network and network solutions that minimise total system costs whilst ensuring energy and system strength requirements are satisfied where feasible.

2.4.1 Incorporate system strength within the NEM market model

An additional layer of complexity is required to co-optimise system strength requirements and the energy supply-demand balance within a market dispatch model. Compared to an energy market model, Baringa's co-optimised energy and system strength model additionally incorporates:

- System strength requirements.
- Contributions of all candidate solutions to system strength requirements.
- Potential new build solutions for system strength, including generation and storage technologies.

The addition of these parameters enables the model to determine outcomes to meet both electricity demand and system strength obligations, whilst minimising the combined costs of investment in new build system strength solutions and generation costs associated with market dispatch.

System strength requirements

Within Baringa's NEM market model, requirements for system strength are defined at six system strength nodes in NSW via two categories:

- **Minimum Fault Level**: the fault level requirement to maintain overall system stability, ensuring network protection and correct operation of voltage control devices.
- **Stable Voltage Waveform:** also referred to as the 'Efficient level', that represents the obligations for Transgrid to support stable connection and operation of IBR.

Transgrid's system strength obligations are represented as constraints in Baringa's market modelling. These obligations are further detailed in Section 4.2. The constraints are formulated to ensure that the minimum and efficient level system strength requirements are met in every time-interval over the modelled horizon, where feasible. The constraints incorporate interstate system strength contributions, the impact of planned outages of critical transmission lines and in the market modelling of market benefits stage, the planned maintenance of new build synchronous condensers (Section 4.2).

Further information as to the IBR projections used to calculate the Efficient level need and develop efficient level system strength constraints is provided in Section 3.1.

Contributions to system strength

The system strength coefficients for each candidate system strength solution are included via the system strength constraint equations to represent the contribution towards system strength requirements at each of the six NSW system strength nodes. Further detail on the methodology is provided in Section 4.1.

New build solutions for system strength

Existing, committed and anticipated projects with the capability to provide system strength are inadequate in meeting future system strength requirements, and additional new-build solutions are therefore considered as part of the portfolio optimisation process. The technical and economic parameters assumed for potential system strength solutions are further detailed in Section 3.3. These input assumptions are included in the portfolio optimisation model, allowing the model to consider the cost and dispatch of new solutions for the purpose of meeting the system strength obligations.

2.4.2 Calculate initial system strength coefficients for solutions

System strength 'coefficients' were calculated and assigned to each individual system strength solution in PLEXOS to represent their fault current contribution to each of the six system strength nodes. The coefficients vary on an annual basis to reflect changes in the power system. For coal and hydro units, contributions were modelled with even greater granularity. Their coefficients dynamically change based on the number of other coal or hydro units online at the same or nearby points of connection. The fault current contribution of each solution is dependent on factors such as its fault current at point of connection, location and network impedance.

System strength is dynamic and exhibits non-linear behaviour. The fault current output of an individual unit varies across time as it is contingent on the operational status of other units and the condition of the transmission network. For the PLEXOS system strength modelling, Transgrid needed to ensure they were accurately estimating the fault level coefficients of each unit. See Section 4.1.1 for a more in-depth analysis of system strength and fault level current contribution.

Simplifications were necessary to apply the complex and non-linear relationships within PLEXOS. Transgrid developed the initial fault level coefficients for each of the more than 100 proposed solutions in PSS®E. For solutions other than coal or hydro, coefficients were derived from a synchronous generator dispatch profile informed by the 'energy-only' market model with the addition of a portfolio of synchronous condensers identified through PADR modelling. The combination of synchronous machines online during this calculation affects the fault current contribution of each individual unit – i.e. generally dispatch profiles with higher total fault current levels result in lower coefficients for each solution compared to dispatch profiles with lower total fault current levels, which yield higher coefficients. To improve the accuracy of the system strength representation in PLEXOS during periods when gaps are more likely, a dispatch profile was selected to generate coefficients which represent NSW fault current levels in an average of the bottom 30th percentile.

For multi-unit hydro and coal power stations, the fault level contribution per unit decreases as more units are generating simultaneously, as higher local fault levels increase the network impedance seen by each subsequent unit.

To capture this localised effect, when multiple coal or hydro units are online at the same time, a more detailed modelling approach was adopted. Refer to Section 4.1.1 for further information. In PSS®E, Transgrid modelled over 4,000 coal unit combinations and more than 24,000 hydro unit combinations to assess each unit's fault level contribution to each node in each combination. Baringa then used this dataset to develop dynamic coefficients in PLEXOS that adjust based on which specific combinations of coal or hydro units are online.

The outcome of this modelling was an initial set of coefficients used for the first iteration of portfolio formation modelling. The coefficients were then 'tuned' in subsequent stages to improve the accuracy, using updated dispatch profiles based on the optimised portfolio of solutions, identified as an outcome of Baringa's PLEXOS portfolio optimisation model.

2.4.3 Optimise and identify the system strength portfolio

The Baringa portfolio optimisation model determines the least-cost generation and storage dispatch and system strength solution development plan for NSW. This approach, using the Long-Term Plan phase in PLEXOS, solves a Mixed-Integer Linear Programming model to co-optimise unit commitment and capacity expansion with respect to electricity demand and Transgrid's system strength obligations. This process ensures sufficient system strength provision across all NSW system strength nodes to meet both the minimum and efficient level requirements in each time interval, where feasible, across a 20-year horizon.

The Baringa portfolio optimisation model co-optimises system strength requirements and energy market outcomes in a total system cost minimisation which considers the following costs:

- Variable generation costs, including fuel, start and shut-down and variable operating and maintenance costs

Capital and operating expenditure of new-build system strength solutions

- The cost of additional emissions incurred due to re-dispatch of existing and committed and anticipated solutions in meeting system strength requirements

In doing so, the model determines the least-cost generation and storage dispatch and system strength solution development plan for NSW, including:

- The dispatch of market participants, including synchronous machines which provide system strength services as a byproduct of their generation or consumption of electricity
- The build path of new system strength solutions
- The build path of technology upgrades to existing, committed or anticipated solutions to enable provision of system strength services

Whilst respecting the following constraints:

- Meeting NSW electricity demand
- Satisfying the NSW minimum and efficient level system strength requirements simultaneously across six defined system strength nodes
- The physical limitations of the transmission system (and selected NSW gas pipelines) alongside the energy and technical limitations upon energy resources

The Baringa portfolio optimisation model ensures that Portfolio Options were constructed at least-cost and explicitly considers the interdependence of system strength and energy market outcomes. The model considers unit commitment for dispatch of synchronous machines, resulting in the dispatch and capacity expansion problem being a Mixed-Integer Linear Programming problem. For tractability[10] reasons, capacity expansion of new build system strength solutions is linear. This build path is then 'integerised' in a later step, described in Section 2.4.5.

The initial system strength portfolio of solutions is determined by identifying solutions which meet one of following criteria:

1. existing, committed and anticipated solutions which demonstrates a change of operation when co-optimised to meet system strength requirements, compared to typical electricity market operation (with no co-optimisation of system strength requirements); or
2. technology upgrades to existing, committed or anticipated solutions, assessed as optimal to meet system strength requirements at minimum system cost; or
3. new build system strength solutions assessed as optimal to meet system strength requirements at minimum system cost

Table 2 provides additional detail about the requirements that solutions needed to meet to be considered as part of the portfolio of solutions.

[10] 'Tractability' refers to ensuring the computational feasibility of the modelling problem within an appropriate time span.

Table 2. Portfolio formation criteria

Type of system strength solution	Description and inclusion criteria	Examples of possible solutions
Existing, committed or anticipated solutions with demonstrated changes in behaviour	Existing, committed or anticipated solutions that do not require an upgrade to provide system strength, however, require a change in behaviour to provide system strength beyond that which they are providing through energy market dispatch alone. If the portfolio optimisation determines that the re-dispatch of the solution is part of the least-cost generation and storage dispatch and system strength solution development plan for NSW, the solution is a part of the Portfolio Option.	Existing coal, gas, hydro or pumped hydro energy storage (PHES) plant.
Upgrade to existing, committed or anticipated solutions	System strength solutions that are upgraded to enable or enhance the provision of system strength within the portfolio optimisation modelling are included in the Portfolio Option.	Committed and anticipated grid-following BESS upgraded to grid-forming mode Hydro units that require upgrades to operate in synchronous condenser mode ISP 'modelled' grid-following BESS upgraded to grid-forming mode
Dedicated new build system strength assets	All new build assets that are part of the least-cost generation and storage dispatch and system strength solution development plan for NSW, are included in the portfolio. Within the portfolio construction, capacity expansion decisions are driven for system strength purposes only, as the NEM-wide capacity expansion solution that meets market energy requirements at least-cost is incorporated as a fixed input. The optimisation accounts for the contribution of new assets to both system strength and the energy market.	Network synchronous condensers EOI-proposed grid-forming BESS 'Targeted' grid-forming BESS (either non-network or network) New build synchronous machines

2.4.4 Validate and recalculate system strength coefficients

After an initial run through the PLEXOS Long-Term model, the system strength coefficients were 'tuned' in an iterative feedback loop.

The PLEXOS market model identified the combination of existing and new system strength solutions required to meet the system strength requirements in each time interval over the modelled horizon. Data for each individual timestamp, representing different configurations of system strength solutions, was then modelled in PSS®E to calculate an accurate fault level contribution of each unit to the six system strength nodes.

The fault level coefficients (i.e. the contribution of each unit at each node) were then optimised for low fault current periods, which is when system strength constraints are most likely to bind. This is done by averaging PSS®E-calculated fault level contributions across the bottom 30% of intervals over the year, representing the lowest third of the timestamps sorted by total NSW fault level.

These averaged coefficients became the updated coefficients for use in the PLEXOS modelling. This process was iterated twice (where PLEXOS' Long-Term modelling 'formed' the optimal portfolio of solutions), until the coefficient inputs in the PLEXOS market model and the outputs of the PSS®E modelling converged.

More detail on this process is provided in Section 4.1.

The output of this process is a refined set of coefficients for each of the system strength solutions to represent the fault current contribution to each of the six system strength nodes in each financial year over the modelled horizon. The final coefficients are then used in the portfolio optimisation model to develop the preliminary portfolio of system strength solutions.

2.4.5 'Integerisation' of the system strength portfolio

The preliminary portfolio optimisation identifies the optimal portfolio to meet system strength requirements, including build decisions of network and non-network solutions. The build decisions were linear (i.e. able to build "part" of a solution) to enable tractable co-optimisation across the 2^{100} potential build combinations to simultaneously meet system strength constraints and energy requirements.

The portfolio of linear solutions is transformed into a portfolio of discrete solutions (i.e. build or don't build) by an 'integerisation' process for each system strength solution. Decisions to integerise new build system strength solutions were made with respect to the PSS®E validation procedure described in Section 2.4.6.

2.4.6 Assess portfolio robustness, resolve identified system strength gaps, and refine locations

The Baringa portfolio optimisation model represents the NEM transmission network using the sub-regional topology as per AEMO's ISP methodology, with minimum and efficient system strength requirements defined using constraints for each of AEMO's six system strength nodes in NSW. The locations of generators, storage and dedicated system strength solutions are mapped to their nearest system strength node.

Since IBRs are not all located at a system strength node, additional power system simulations were performed in PSS®E and PSCAD™ (both programs model the transmission network in greater detail and its power system dynamics than the PLEXOS market model), to validate that the portfolio of solutions meet Transgrid's system strength requirements.

System strength portfolios are validated through Transgrid's detailed PSS®E modelling. The PSS®E simulations represent the NSW transmission network with a high level of detail, which allows the dynamics of the power system to be captured more accurately than the PLEXOS market model which relies on static values.

Minimum level validation

The simulations ensure the portfolio outcomes optimised by PLEXOS perform as expected to meet the minimum level system strength requirements. The portfolios were simulated in PSS®E under a large set of sample timestamps to represent the complete range of possible generator unit configurations, with a full N-1 contingency assessment. In PSS®E, existing and committed generators are placed at their precise location in the network and new entrant IBRs are located based on Transgrid's assessment of likely projects (informed by connection enquiry data) or REZ locations (informed by EnergyCo). Where gaps in system strength are identified in the PSS®E simulations, system strength solutions are introduced or brought forward from the preliminary optimised portfolio to resolve the gap.

In addition, Transgrid have assessed the solution to the Broken Hill requirement using PSS®E modelling and an out-of-PLEXOS economic cost assessment, due to its large electrical distance from the nearest system strength node.

Efficient level validation

In the PACR, Transgrid assessed the efficient level in PSS®E following the Available Fault Level (AFL) methodology outlined in the System Strength Impact Assessment Guidelines. This method has been adopted by AEMO as a proxy for system strength. However, for the efficient level of system strength, the AFL methodology does not account for the four criteria defining a stable voltage waveform. Transgrid compared AFL with the Electromagnetic Transient (EMT) model methodology by assessing the synchronous fault level contribution required from synchronous condensers to achieve voltage waveform stability across the NSW network.

The assessment showed general agreement at a state level, confirming AFL as a suitable planning-level estimate. However, at more granular scales, some areas required higher or lower contributions than those indicated by AFL, due to factors it cannot capture (e.g. Static VAR Compensator (SVC) tuning). Therefore, Transgrid validated the optimised portfolio at both the state level and in high-renewable areas using EMT modelling in PSCAD™, specifically within South-West REZ and Hunter Central Coast REZ.

Transgrid undertook detailed PSS®E modelling to optimise and validate the distribution of the network solutions that were identified as part of the optimal portfolio of solutions from the PLEXOS modelling process. This process refined the synchronous condenser locations based on insights provided by the analysis (such as critical planned outage periods, planned maintenance and N-1 contingency) and insights from Option Feasibility Studies of site locations (for example, site specific factors including available land within Transgrid's substations) to ensure the solutions are optimal. This stage also involved detailed PSCAD™ modelling of the stable voltage waveform support required for connection of the forecast REZ IBR capacity, to ensure strategic location of the necessary solutions within proximity to connecting IBRs to meet efficient level requirements.

To ensure the final synchronous condenser build path reliably meets Transgrid's system strength requirements, the refined synchronous condenser build path underwent a validation feedback loop in PSS®E to identify any system strength gaps for the minimum level. Where gaps were identified during periods in which synchronous condensers could feasibly be delivered, units were either relocated or their commissioning dates adjusted and re-validated in PSS®E.

2.5 Market dispatch optimisation

Following the portfolio optimisation process and the determination of the optimal portfolio of system strength solutions, Baringa undertakes half-hourly, time-sequential, least-cost NEM dispatch optimisation modelling spanning a 20-year horizon from 2025/26 to 2044/45. The modelling methodology follows the AER RIT-T guidelines, and includes the market dispatch modelling of a Base Case, the Portfolio Options, and various sensitivities.

As system strength provision is a function of whether the machine is synchronised (operational) or not, rather than a function of energy generation, unit commitment decisions for synchronous generators are important in the provision of system strength. Consequently, unit commitment decisions for synchronous machines are integer and a Mixed-Integer Linear optimisation occurs.

The Baringa NEM market dispatch model co-optimises system strength requirements and energy market outcomes in a total system cost minimisation which considers the following costs:

- Variable generation costs, including fuel, start and shut-down and variable operating and maintenance costs
- Voluntary load curtailment (through demand side participation (DSP) and involuntary load curtailment via energy market dispatch

In doing so the model determines the least-cost generation and storage dispatch and unit commitment schedule for the NEM, including synchronous machines which provide system strength services as a byproduct of their generation or consumption of electricity.

Whilst respecting the following constraints:

- Meeting electricity demand in each region of the NEM, and if not feasible then incurring involuntary load curtailment
- Satisfying the NSW minimum and efficient level system strength requirements simultaneously across six defined system strength nodes
- The physical limitations of the electricity transmission system, including interconnector flow limits and intra-regional flow limits
- Physical limitation on selected gas transmission pipelines[11]
- Technical limitations for generation and storage assets (including minimum loads for synchronous generators)

[11] A daily NEM-wide gas constraint (consistent with AEMO's 2024 ISP) was included in all modelling stages with an additional, specific pipeline constraint for two NSW gas generators (consistent with GHD advice) included in the market dispatch optimisation stage.

Within the market dispatch optimisation model, the portfolio of system strength solutions undergoes a final validation process to ensure system strength constraints remain adequately satisfied across the modelled horizon when modelled with half-hourly granularity.

The market dispatch outcomes feed into the modelling of market benefits and dispatch analysis to assess the net market benefits (as calculated in Section 7) and the operational behaviour of non--network solutions for each option.

2.5.1 Energy-only market dispatch model

Baringa's market dispatch optimisation model is used to determine the least-cost market dispatch and unit commitment schedule for the NEM in the absence of system strength constraints (deemed 'energy-only').

The purpose of this step is to provide an understanding of how the market would dispatch in the absence of system strength constraints. This provides a reference point to determine the level of 're-dispatch' of system strength solutions when dispatch is optimised for both energy and system strength requirements.

2.5.2 Co-optimised system strength and energy market dispatch model

The co-optimised system strength and energy market model determines the lowest cost unit scheduling that meets both energy and system strength requirements, under a given Portfolio Option.

Changes in dispatch of synchronous machines are identified by comparing the unit commitment outcomes under the co-optimised dispatch modelling to outcomes under the energy-only dispatch modelling. Market dispatch outcomes for Portfolio Option 1 are outlined in Section 6.

This model is used to extract costs and benefits by market benefit class for the Base Case and each option, as described further in Section 7. Comparison against the Base Case then allows identification of the net change to economic benefits for each of the options.

This section describes the analysis of market benefits used to calculate the net market benefits for each Portfolio Option, the Base Case and the Portfolio Option sensitivities over the 20-year modelling horizon from 2025/26 to 2044/45. A pre-tax real discount rate of 7% was adopted, consistent with the IASR central assumption, for the calculation of the net present value of costs.

The RIT-T guidelines require net market benefits to be calculated for each Portfolio Option relative to the Base Case. The Base Case refers to the 'state of the world' in which no action is taken and is described in Section 5.1. Net market benefits for all Portfolio Options were calculated relative to the Base Case, except for the calculation of involuntary load curtailment via system strength gaps. As explained in Section 2.4.3, due to the large amount of unserved energy from system strength gaps in the Base Case, unserved energy that was common across the Portfolio Options was removed to prevent the 'swamping' of other benefits categories. Instead, only the difference in involuntary load curtailment via system strength gaps between the options is presented.

2.5.3 Market benefit classes

When assessing the benefits of different Portfolio Options, the following classes of market benefits were considered material and have been included in the market benefit assessment:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in Australia's greenhouse gas emissions
- changes in costs for parties, other than the RIT-T proponent
- changes in the timing of expenditure
- changes in voluntary load curtailment
- changes in involuntary load curtailment via system strength gaps
- changes in involuntary load curtailment via energy market dispatch

Competition benefits, option value, transmission losses, differences in REZ transmission costs[12] and changes in ancillary service costs are not considered to be material for this RIT-T and so have not been calculated.

2.5.4 Value of emissions

Following changes to both the National Electricity Objective (NEO) in September 2023, the National Electricity Rules (NER) on 1 February 2024 and the Review of the cost benefit analysis guidelines and RIT application guidelines in November 2024[13], TNSPs must now consider changes in Australia's greenhouse gas emissions (where material)[14].

On the 28 March 2024, the Ministerial Council on Energy (MCE) published a statement about the interim value of greenhouse gas emissions reduction – this set out the methodology for how the Value of Emissions Reduction (VER) should be determined[15].

Within the portfolio optimisation process, we have captured the *incremental* emissions that come from the re-dispatch of existing or committed and anticipated assets for system strength purposes.

Within the market dispatch optimisation outlined in Section 2.5.2 the value of emissions is not considered as part the optimisation problem. Instead, emissions are calculated ex-post.

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[12] Differences in REZ transmission costs refer to market benefits associated with varied transmission investment across the modelled Portfolio Options and sensitivities. As Transgrid's system strength obligations are constructed against a defined transmission network (see Section 3.1) this modelling does not assess the benefits of additional transmission investment to ensure consistency with the constraint formulation methodology.

[13] AER, Review of the cost benefit analysis guidelines and RIT application guidelines https://www.aer.gov.au/system/files/2025-05/AER%20-%20Cost%20Benefit%20Analysis%20and%20Regulatory%20Investment%20Test%20guidelines%20review%20-%2021%20November%202024%20-%20explanatory%20statement.pdf

[14] AEMC, Harmonising the energy rules with the updated energy objectives, February 2024, https://www.aemc.gov.au/sites/default/files/2024-01/information_sheet.pdf

[15] AER, Valuing emissions reduction, AER final guidance, May 2024, https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024

2.5.5 Involuntary load curtailment via system strength gaps

This section describes the methodology taken to calculate the cost of system strength gaps. System strength gaps can have considerable consequences. As such, calculations of the associated cost of system strength gaps for the Base Case and each Portfolio Option are required to fulfil the RIT-T requirements.

Under the Base Case, where no action is taken to procure new system strength solutions, there will be significant gaps in system strength provision to meet minimum and efficient level requirements over the horizon of the assessment.

The risk of system strength gaps were also found to occur in all options or sensitivities in early years of the modelled horizon prior to the entry of sufficient new solutions. In this situation, the system relies primarily on existing and committed non-network solutions to meet system strength requirements.

The impact of system strength gaps may include:

- 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 could occur. In this instance, AEMO would likely intervene to prevent this situation from occurring, by pre-emptively disconnecting susceptible generators and equipment, which in turn could result in involuntary load curtailment.
- If the efficient level of system strength is not met, curtailment of IBR would likely occur and ultimately involuntary load curtailment may occur if the remaining generation is insufficient to meet system demand.

Methodology to calculate the quantity of involuntary load curtailment via system strength gaps

It is inherently complex to quantify the risks of system strength gaps. Factors influencing the complexity of this analysis include the interdependencies and non-linear effects in the power system that mean disturbances could propagate in quick succession, stochastic variables, data availability and forecasting the intervention of AEMO to avoid gaps in system strength.

Transgrid have developed a methodology to estimate the probable involuntary load curtailment associated with system strength gaps. This methodology is purposely simple – undertaking analysis involving more sophisticated modelling techniques and assumptions to assign a cost to system strength gaps would involve a level of time and effort which is disproportionate to the impact on the outcome of the analysis (in particular, because the entire purpose of this reliability corrective action RIT-T is to avoid these situations).

Minimum level requirement gaps

The constraint violation outputs for the minimum level requirement are taken on a time-interval basis. Involuntary load curtailment (represented by USE_i) is assumed to be proportional to NSW underlying demand and the ratio of the total minimum-level gaps across each six system strength nodes divided by the total minimum fault level requirements at each node divided by four (to provide a conservativeness factor into the analysis, discussed below). The calculation for each time interval is shown in the equation below.

$$USE_i = NSW\ Demand_i \times \left(\frac{\Sigma \text{ minimum level gap at each node}_\text{i}}{\Sigma \text{ minimum level requirement at each node}_\text{i}}\right) \times 0.25$$

Efficient level requirement gaps

The constraint violation outputs for the efficient level requirement are taken on a time-interval basis. The quantity of curtailed IBR is assumed to be proportional to NSW underlying demand and the ratio of the total efficient-level gaps across each six system strength nodes divided by the total efficient fault level requirements at each node divided by four (to provide a conservativeness factor into the analysis, discussed below).

Involuntary load curtailment via system strength gaps are assumed to be proportional to the quantity of curtailed IBR calculated, and the ratio of corresponding NSW demand in each time-interval divided by the maximum forecast NSW demand in that financial year. i.e. during higher demand periods, more involuntary load curtailment occurs and during low demand periods, less involuntary load curtailment occurs because there is likely to be other generation available to ramp up. The remainder of curtailed IBR is assumed to be met by alternative generation sources, including renewables in other areas of the network. For simplicity, this cost is assumed to be $0.

The calculation for each time-interval is shown in the equations below.

$$IBR\ Curtailed_i = NSW\ Demand_i \times \left(\frac{\Sigma \text{ efficient level gap at each node}_\text{i}}{\Sigma \text{ efficient level requirement at each node}_\text{i}}\right) \times 0.25$$

$$USE_i = IBR\ Curtailed_i \times \left(\frac{\text{NSW Demand}_\text{i}}{max(NSW\ POE10\ Demand)_{FY}}\right)$$

Scaling factor applied to gaps

The precise scaling factor (to provide a conservativeness factor into the analysis) between system strength gaps and involuntary load curtailment via system strength gaps is uncertain and has been represented by the 0.25 factor in the above equations. We note that the choice of this factor does not materially affect the ranking of any of the options.

Combine gaps

In instances where both minimum and efficient level gaps occur, the combination of the minimum and efficient level involuntary load curtailment is capped at a maximum of the underlying NSW demand in the corresponding time-interval.

Remove market benefits common to all Portfolio Options

The Base Case, with no reliability corrective actions (i.e. no entry of new system strength solutions), has increasing system strength gaps which become very large as coal generators retire. This is not a situation Transgrid plans to let occur, and the NER obligations and this RIT-T have been initiated specifically to avoid them. Most of the costs associated with system strength gaps in the Base Case will be avoided by each of the Portfolio Options.

As each option will materially address the system strength requirements, the common market benefits associated with avoided involuntary load curtailment via system strength gaps compared to the Base Case are removed from the total market benefits of each option so that they do not swamp the other benefit sources. The ranking of each option is unaffected by this as only the market benefits that are common to all Portfolio Options are removed.

Assigning a cost to involuntary load curtailment via system strength gaps

To calculate the cost of involuntary load curtailment via system strength gaps, the Value of Customer Reliability (VCR, expressed in $/MWh) is applied. The AER's most recent VCR assumption from the 2024 Values of Customer Reliability Report ($30,860/MWh post de-escalation to real FY23/24 dollars) is adopted for the purpose of this assessment. In the PACR, sensitivity testing was also undertaken to test the impact of applying 30% higher and lower VCR values (i.e. consistent with the AERs state level of confidence)[16].

2.5.6 South West REZ market benefits

This section describes the out-of-model assessment applied to quantify the impact of the earliest Dinawan synchronous condenser deployment timing on meeting efficient level system strength requirements in the South West REZ and to quantify the impact on total system costs for incorporation in the net market benefit assessment for each portfolio option.

Transgrid has identified that one network synchronous condenser at Dinawan is part of all portfolio options, through assessment outside of PLEXOS of the efficient level requirements in South West REZ. Using PSCAD™, detailed 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.

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

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.

3 Input assumptions

Section 3.1 provides additional detail on the key inputs, assumptions and data sources used. The subsequent subsections provide more detail on the treatment of outages, system strength solutions and asset-specific inputs.

3.1 Step Change equivalent scenario

Baringa optimised the least-cost generation and storage dispatch and capacity development plan for the NEM, associated with the input assumptions generally derived from the Step Change scenario under AEMO’s 2024 Final ISP, with more up-to-date and relevant market information considered where available.

This is consistent with the scenario and approach used by AEMO to calculate the IBR forecast which determines Transgrid’s efficient level system strength obligations.[17] IBR projections from this “Step Change equivalent” scenario was used to model the stable voltage waveform (efficient level) requirements within both the portfolio optimisation and market dispatch optimisation modelling. Further detail on this approach is provided in Section 3.1.2.

Additional information sources were used where these were considered more up to date than the assumptions under AEMO’s 2024 Final ISP, and could be included within modelling timeframes[18]. This included updates to the following categories of assumptions:

Updates to modelled policies & capacity mix:

- NSW Energy Infrastructure Storage Target updated to reflect the additional Long Duration Energy Storage target of 12 GWh by 2033/34 atop the previously specified targets of 16 GWh & 2 GW due by 2029/30[19].
- Update of NSW coal closure schedule to reflect the delayed retirement of Eraring Power Station to August 2027[20].
- Updates to Committed and Anticipated plant as per AEMO’s October 2024, Generation Information document[21].

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[17] AEMO, *System Strength Report 2023*, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-system-strength-report.pdf?la=en

[18] Inputs from AEMO’s Draft 2025 IASR, 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 were not expected to materially change the outcomes of the RIT-T.

[19] NSW DCCEEW, *Position paper: Long Duration Storage Review*, https://www.energy.nsw.gov.au/sites/default/files/2024-10/20241017_NSW_DCCEEW_Long_Duration_Storage_Review_Position_Paper.pdf

[20] NSW DCCEWW, Summary of agreement between the State and Origin on its plans for Eraring Power Station, https://www.energy.nsw.gov.au/sites/default/files/2024-05/NSW-202405-Public-summary-of-Generator-Engagement-Project-Agreement.pdf

[21] AEMO, *October 2024 Generation Information*, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

Updates to transmission development and REZ development pathways:

- Delayed commercial operation date (COD) of the New England REZ to reflect information published in AEMO's Transmission augmentation information in December 2024, which reflects EnergyCo advised timing[22]. New England REZ Stage 1 and 2 have modelled start dates of 2032/33 and 2033/34 respectively.
- Accelerated COD of the Hunter-Central Coast REZ to reflect latest timing information from EnergyCo and proponent Ausgrid of December 2027.
- Advanced COD of Humelink to reflect the latest proponent (Transgrid) advised date of December 2026.

Updates to bidding behaviour of coal plant:

- Baringa implemented strategic bidding of all coal units in the NEM from the start of the modelling horizon (1/7/2025) to the modelled retirement date of Eraring (17/8/2027). From this date onwards to the end of the horizon short-run marginal cost (SRMC) bidding as per the PADR methodology.

Table 3 provides a comprehensive overview of the sources for inputs and assumptions used.

Table 3. Key inputs and 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. 2000 MW/1600 MWh of eligible large-scale storage by 2029/30. Additional 1200 MWh of eligible large-scale storage by 2033/34.
Tasmanian Renewable Energy Target (RET)	State policy	2023 IASR. Minimum 15,750 GWh of renewable generation 2029/30 and 21,000 GWh 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.

[22] AEMO, *Appendix 5. Network Investment*, June 2024, https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en

Key input parameters	Input Category	Source
		Minimum 2.6 GW of eligible large-scale storage by 2030 and 6.3 GW 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
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.
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.

Key input parameters	Input Category	Source
		Exception of gas variable operating and maintenance costs.
Maintenance rates	Capacity mix	2023 IASR
Generator reliability settings	Capacity mix	2023 IASR. Exceptions applied based on proponent information.
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.

The other two Final 2024 ISP scenarios (i.e. Progressive Change and Green Energy Export scenarios) have not been modelled as they do not align with Transgrid's system strength obligations (which are driven by the Step Change scenario and set by AEMO).

This approach is consistent with AER's guidance note on system strength[23].

3.1.1 Generation and Storage Capacity Development Pathway

Baringa optimised the least-cost generation and storage capacity development pathway for the NEM, using the modelling methodology set out in Section 2.3, under the given input assumptions.

The NEM-wide capacity and generation mix in the Step Change equivalent scenario are shown in Figure 8 and Figure 9 respectively. As coal closures occur, the projected generation capacity of the NEM is shown to increasingly shift towards renewables firmed by utility scale storage, hydro and gas.

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

Figure 8. NEM Capacity mix under the Step Change equivalent scenario

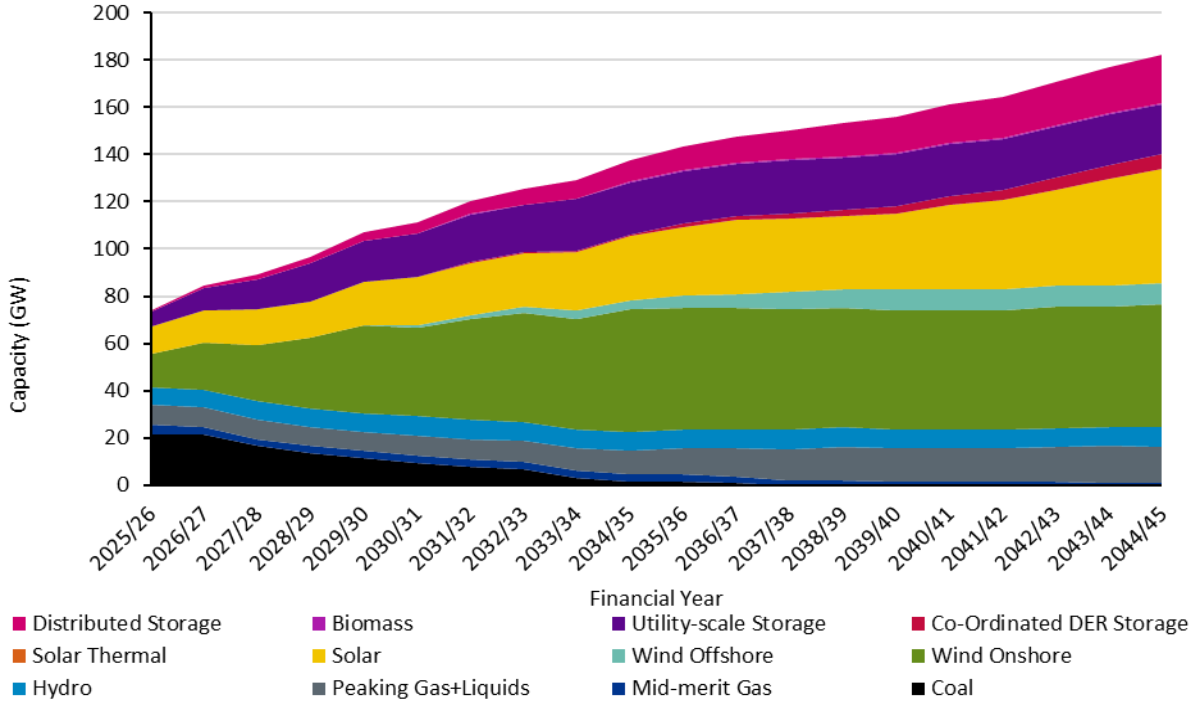
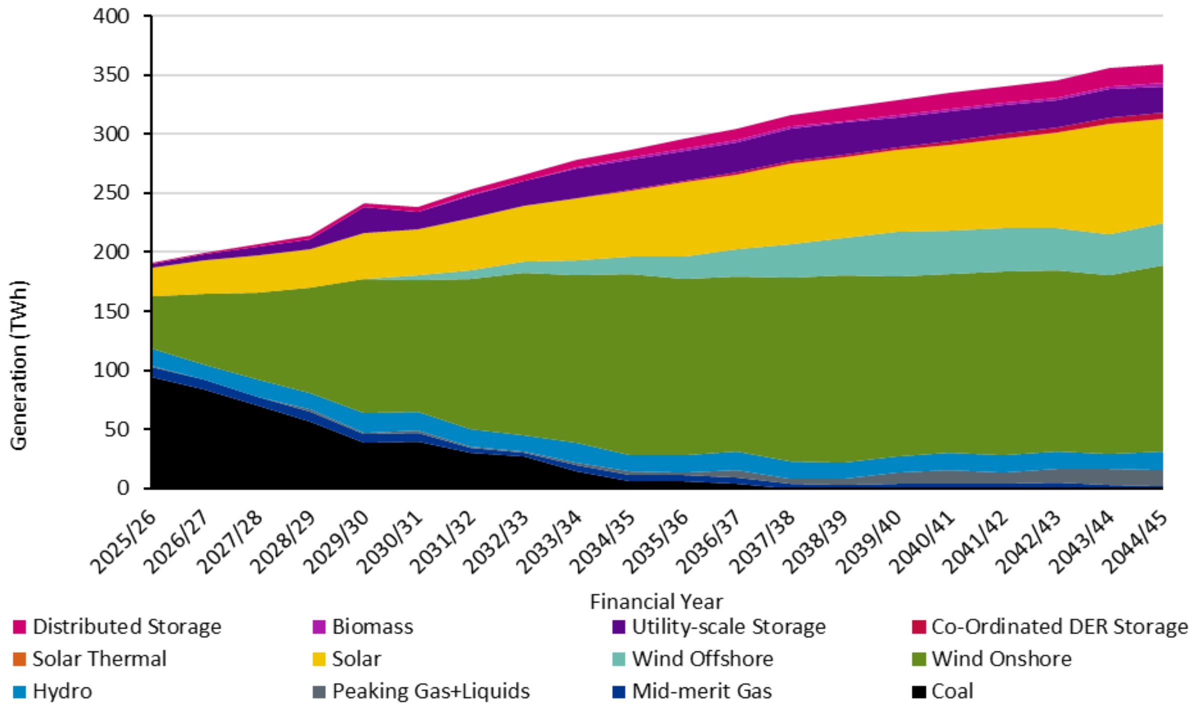


Figure 9. NEM Generation mix under the Step Change equivalent scenario



Coal closure timings are an input to this modelling and, with the exception of Eraring, are common between the Final ISP 2024 Step Change scenario and Step Change equivalent scenario. Renewables, utility-scale storage and hydro are built both as a result of modelled policy constraints and on an economic basis to replace the retiring coal capacity and meet growing electricity demand. Up until 2029/30, the Powering Australia federal policy target and other legislated state policies drive a large proportion of new build renewable capacity. Firming is provided by storage, pumped hydro, mid-merit gas and peaking gas/liquids. Offshore wind is built in stages from 2029/30 to meet the Victorian state governments offshore wind target.

Differences in pathway to the 2024 Final ISP Step Change scenario

The differences in capacity and generation mix between the Step Change equivalent scenario and AEMO's Final ISP 2024 Step Change scenario are detailed below.

The differences in input assumptions (outlined in Section 3.1) drive different build paths of renewables between the Step Change equivalent scenario and the Final ISP 2024 Step Change scenario. This is most clearly seen in NSW and largely related to the delayed New England REZ timing. The clearest example of this can be seen in 2030/31 – the year preceding the assumed COD of New England REZ Stage 1. The installed capacity of onshore wind in the NEM is ~5 GW less in the Step Change equivalent scenario in 2030/31 than the Final ISP 2024 step change scenario. As seen in Figure 11, increased generation volumes from coal, hydro and gas plant are dispatched in place of lower onshore wind and solar generation. This onshore wind capacity delta is largely removed in 2031/32 as the New England REZ Stage 1 reaches its COD and allows new build wind capacity to be built in the REZ.

Figure 10. Difference in NEM capacity forecast between the Step Change equivalent scenario and the AEMO Final ISP 2024 Step Change scenario

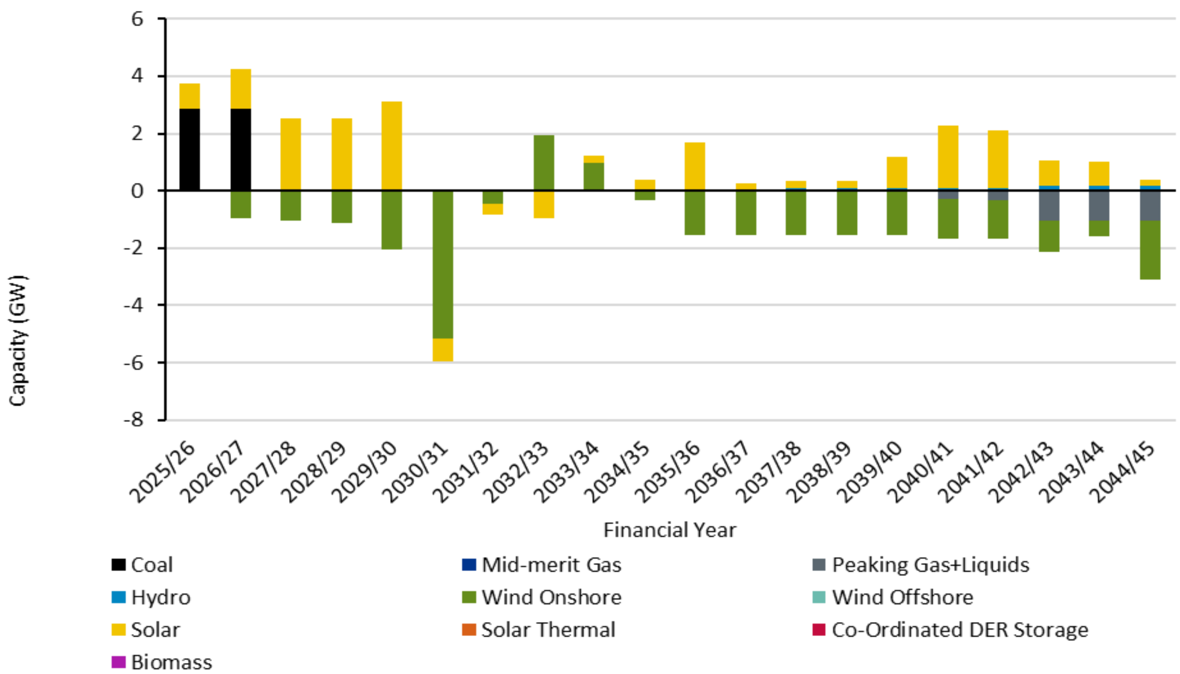
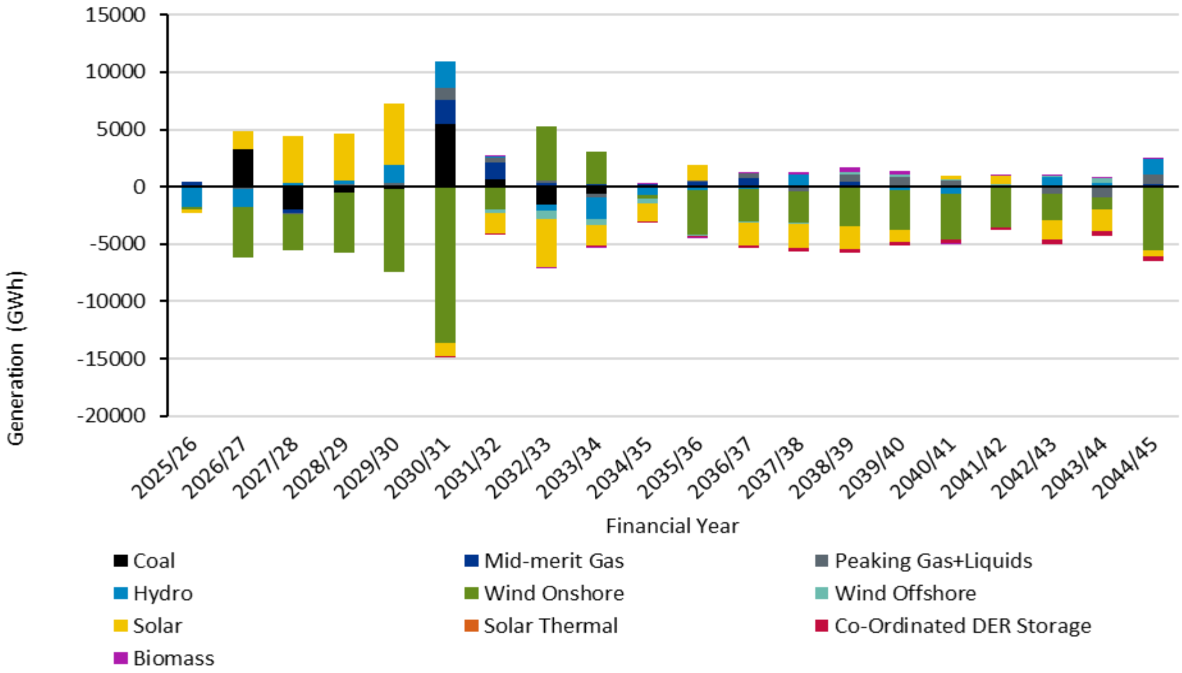


Figure 11. Difference in NEM generation forecast between the Step Change equivalent scenario and the AEMO Final ISP 2024 Step Change scenario (excluding Utility-scale and Distributed storage).



3.1.2 IBR projections used to inform the efficient level requirement

While the overall characterisation of the efficient level requirement has not changed since the PADR and the 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 based on the Final 2024 ISP, updated committed and anticipated generation projects, updated status of network projects and the announced two-year delay in retirement for Eraring Power Station to August 2027.

However, the revised delivery timetable announced by EnergyCo for the completion of the New England REZ Infrastructure Project was not incorporated in AEMO's most recent System Strength Report. The revised timing represents a delay of more than three years to dates previously advised for Stage 1 (from September 2028 to July 2032) and the 2024 ISP Step Change timing for Stage 2 (from July 2030 to January 2034[24]).

The IBR forecast from the Step Change equivalent scenario, which incorporates the changes to the New England REZ timings as well as the material market updates detailed in Section 3.1, was used as the basis to determine Transgrid's efficient level requirements. Transgrid considers it prudent and efficient to take into consideration the latest available information in developing the IBR projection as it will lead to more efficient procurement of system strength solutions than applying forecasts with out-of-date input assumptions. This approach follows guidance by AEMO in the 2024 System

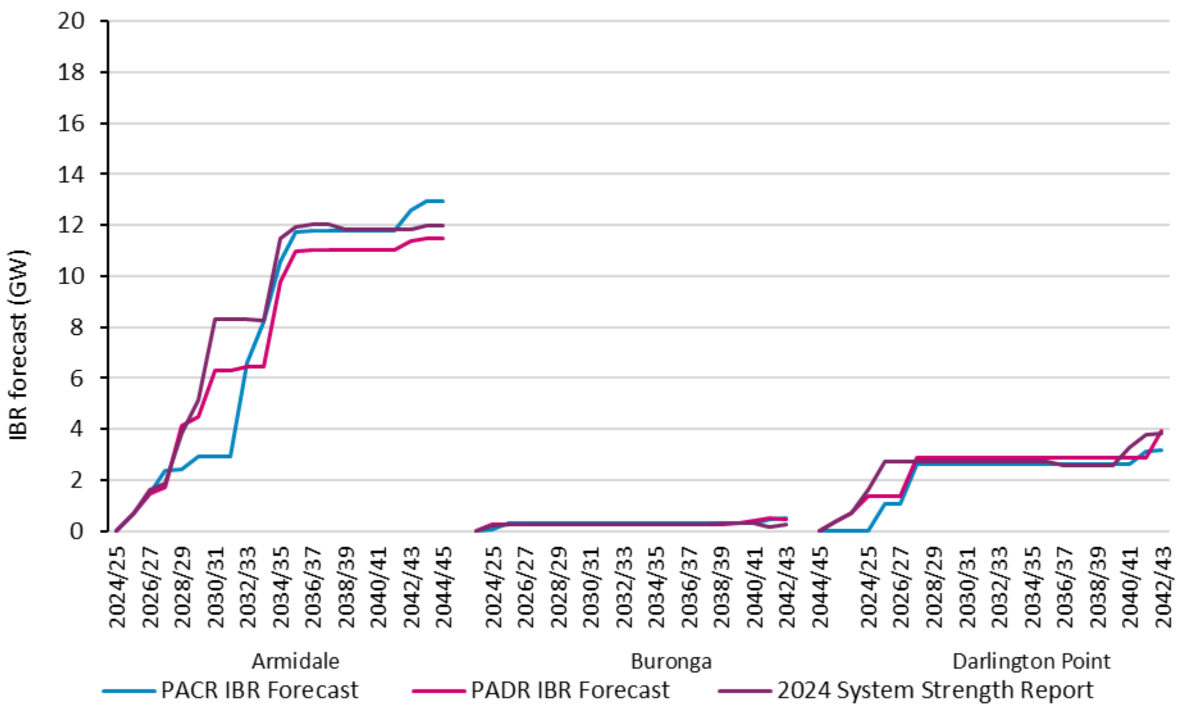
[24] AEMO, *NEM Transmission Augmentation Information*, December 2024. Available at: AEMO | Transmission augmentation information

Strength Report[25] and the AER's guidance note[26], which clarified that SSSPs may use best information available to determine the appropriate provision of system strength.

A comparison of the IBR forecasts used for the PACR and AEMO's 2024 and 2023 System Strength Report (used for the PADR) is shown in Figure 12 and Figure 13. 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 (Stage 1 complete in 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 forecast IBR surrounding the Armidale node to converge with AEMO's 2024 System Strength Report from 2037/38.

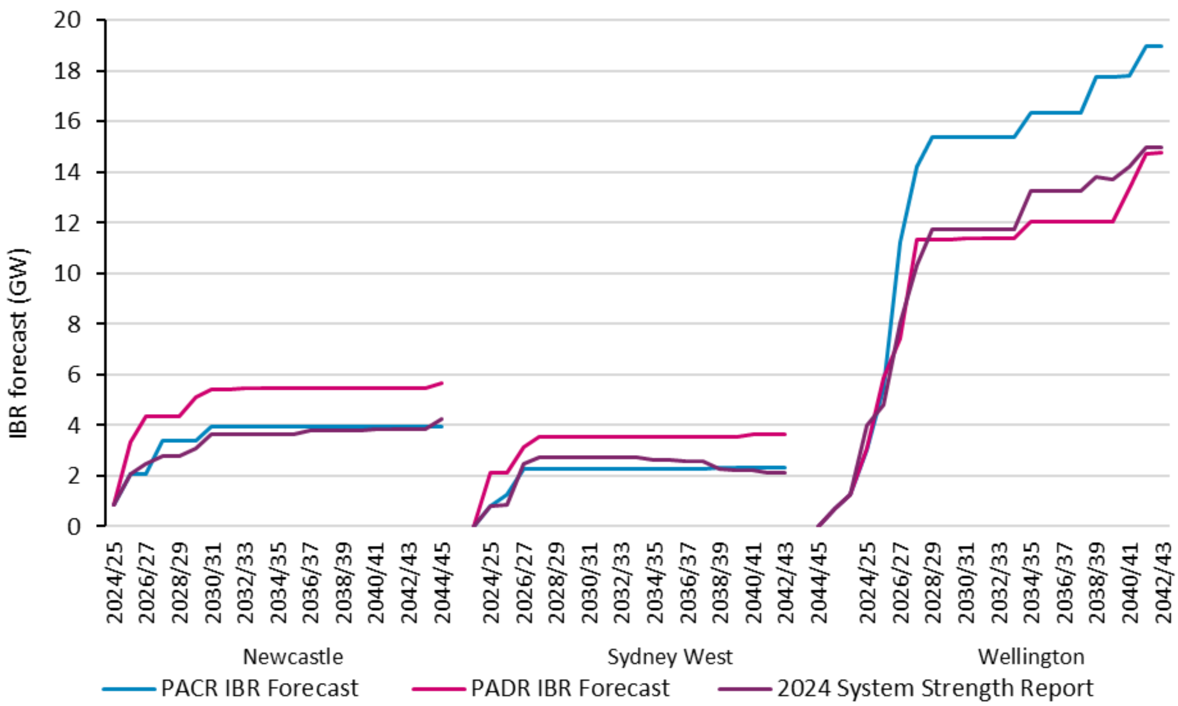
Figure 12. IBR forecasts at the Armidale, Buronga and Darlington Point System Strength nodes



25 p.18, AEMO, February 2025, 2024 System Strength Report

26 AER, December 2024, Efficient Management of System Strength Framework – Guidance note

Figure 13. IBR forecasts at the Newcastle, Sydney West and Wellington System Strength nodes



3.1.3 Self-remediation versus electing to pay the System Strength Charge

Self-remediation assumptions flow through into the efficient level requirement via the quantum of stable voltage waveform support Transgrid will have to supply to meet its efficient level obligations. 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 and 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, which may 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. All these projects have elected to self-remediate under the previous rules and therefore do not require system strength provision provided by Transgrid. These projects have been removed from the IBR forecast that Transgrid is seeking to remediate to avoid over-procurement. Transgrid re-assessed its connection pipeline at the time of market modelling (December 2024) and removed all projects which had elected to self-remediate from its efficient level need.

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 which will opt in and elect to pay the System Strength Charge or self-remediate.

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. Transgrid has not applied arbitrary escalations on the proportion of projects assumed to self-remediate overtime. 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. The approach for the PACR sees a reduction in the efficient level which is expected to avoid over-procurement of system strength solutions.

3.2 Treatment of outages

Both the portfolio optimisation and market dispatch optimisation modelling consider the impacts of:

- generator outages on the available generation capacity for provision of energy, and
- generator outages and network outages towards meeting system strength requirements.

Transgrid undertook detailed PSS®E analysis to incorporate the impact of critical planned network outages on system strength requirements. As these form part of the system strength representation, details are provided in Section 4.2.3

The assumptions determining planned maintenance and unplanned outages of generation and storage projects, including maintenance rates, full and partial forced outage rates and mean time to repair, are aligned with AEMO's IASR 2023.

Discrete generator outage windows are modelled for all generation and storage objects within the portfolio optimisation and market dispatch optimisation modelling. These discrete outage windows cover both planned maintenance and unplanned outage periods.

Planned maintenance events are assigned through a projected assessment of system adequacy (PASA) model. These events are for an equivalent number of days determined by the project's respective maintenance rate. When a generator is offline for maintenance it is unavailable for both energy dispatch and system strength provision. The PASA model optimises the timing of generator maintenance events subject to de-rated capacity reserve margins.

Unplanned outage periods are randomly assigned subject to AEMO's 2023 IASR generation and storage reliability parameters, which determine the frequency and length of unplanned outage events. When assigning unplanned outages, no consideration is given to the timing of planned maintenance events of other projects.

The resulting planned maintenance and unplanned outage schedules are consistently applied across both the portfolio optimisation and market dispatch model to ensure that the same sequence of outages are used across all Portfolio Options.

Coincident outage periods refer to intervals in which multiple coal units across the NEM are unavailable due to planned maintenance or full forced outage events. Co-incident outages are a possible outcome of the PASA optimisation. Given one of the key drivers for potential gaps in NSW system strength is the co-incidental unavailability of NSW coal generators, they are an important consideration in the modelling process.

It was not possible to include discrete maintenance events for new build system strength solutions in the portfolio optimisation stage. Instead, planned maintenance events for new build network synchronous condensers were included as part of the portfolio validation analysis conducted by Transgrid in PSS®E. The PSS®E analysis is incorporated into the market dispatch PLEXOS model during discrete maintenance periods assumed for synchronous condensers to account for the additional system strength than must be procured during maintenance events of network system strength solutions. More detail on how the planned maintenance of synchronous condensers was considered in the PACR can be found in Section 4.2.3.

3.3 System strength solutions

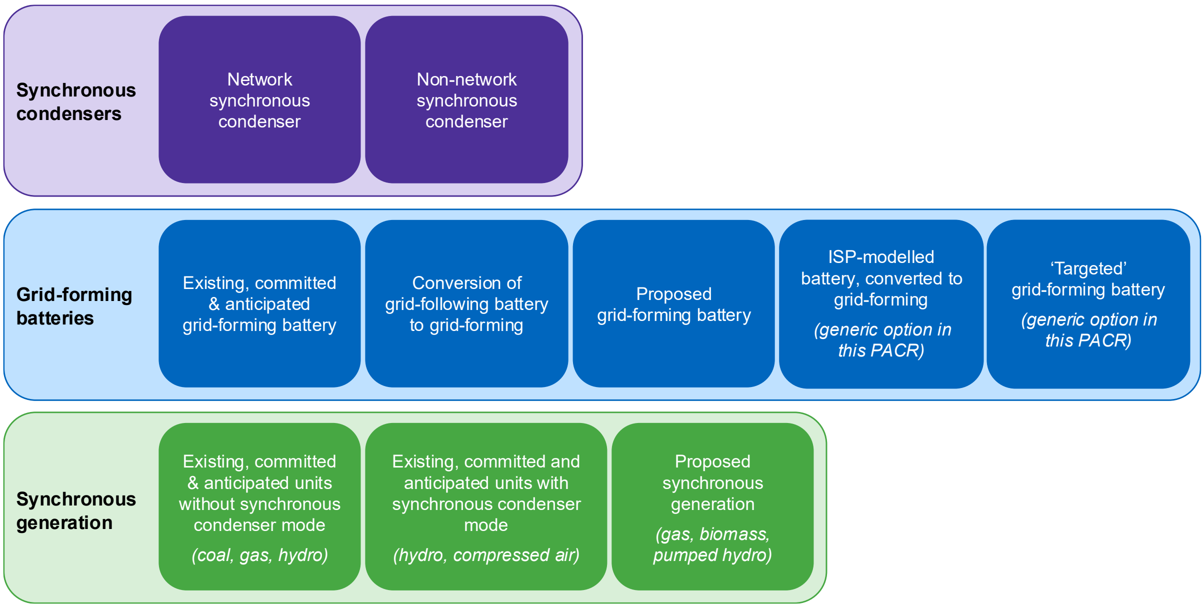
To form optimal portfolios of system strength solutions, the market modelling approach considered more than 100 individual network and non-network system strength solutions (derived from Transgrid's EOI process or from Transgrid-identified network solutions), which leads to more than 2^{100} possible portfolio combinations.

A summary of the system strength solutions considered in this modelling process is shown in Figure 14. The key input and modelling assumptions associated with each of these categories including existing synchronous machines, batteries, new synchronous and network solutions are explained throughout this section.

In general, modelling the participation of these assets in the energy market (e.g. from batteries) is aligned to AEMO's ISP modelling methodology, except where explicitly stated.

All proposed system strength solutions were modelled on a single unit basis. EOI submissions received by Transgrid from prospective proponents of assets on a portfolio basis were separated and modelled as individual assets as a part of the EOI process. Where build costs and/or other required parameters for both network and non-network system strength solutions were not specified in the proponent's EOI submission, AEMO's 2023 IASR values were used. Even where proponents did provide certain inputs via their EOI submission, IASR values were applied in some cases to ensure consistency across the assessment and enable a fair comparison of similar solution types.

Figure 14. Categories of candidate network and non-network system strength solutions[27]



3.3.1 Synchronous condensers

Network synchronous condensers

Network synchronous condensers refer to synchronous condensers owned and operated by Transgrid. All input information for the modelling of network synchronous condensers was provided to Baringa by Transgrid. Transgrid sourced 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 (OEM) quotes (for synchronous condensers) and Transgrid's internal estimating tool for the civil and balance of plant costs.

Transgrid developed cost estimates for synchronous condensers at 15 separate locations. Table 4 presents these locations along with the basis for the cost estimate.

Table 4. Prospective synchronous condenser locations

Nearest system strength node	Synchronous condenser location	Basis for cost estimate
Armidale	Armidale 330 kV	Option Feasibility Study
	Tamworth 330 kV	Options Feasibility Study
	New England REZ	Estimate for Armidale used

[27] Where 'existing' refers to system strength solutions which currently exist or have either committed and anticipated status.

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 ongoing.
	Muswellbrook 330 kV	Average of estimates for Sydney West and Wellington were used
	Synchronous condenser solution in Hunter-Central Coast REZ, East Hub 132 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
Sydney West	Kemps Creek 330 kV	Option Feasibility Study
Wellington	Wellington 330 kV	Option Feasibility Study

Certain synchronous locations considered in the PADR analysis were not considered in the PACR. These locations and the justification for their exclusion is presented in Table 5 below.

Table 5. 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 tractability of market modelling.
Darlington Point 132 kV	
Vales Point 330 kV	
Cooma 132 kV	
Wollar 500 kV	
Sydney West 330kV	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.

A summary of the assumptions made for synchronous condenser is shown in Table 6.

Table 6. Summary of modelled synchronous condenser assumptions

Parameter	Assumption	Source
CAPEX Costs	Site specific.	Based on OEM costs for synchronous condensers and Transgrid internal assessment for all other costs.
OPEX Costs	0.6% of CAPEX	As per ElectraNet's Contingent Project Application[28].
Asset life	A standard asset life of 40 years	AER Guidance[29]
Losses	Manufacturer specific.	Average losses provided by supplier to Transgrid
Availability	Annual availability of 98.9%	Average availability provided by suppliers to Transgrid
Limitation to number of synchronous condensers at any given site	Varies by site analysis.	Provided by Transgrid
Earliest operation date	March 2029 (Earliest credible timing) February 2030 (standard timing)	Provided by Transgrid based on standard timing following expected completion of the RIT-T and lodgement and AER approval of CPA.
Fault current contribution	1,050 MVA Fault level contribution provided by each synchronous condenser, as measured at the point of connection to the transmission network	Transgrid discussions with suppliers

[28] ElectraNet *Contingent Project Application*, August 2019, https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf

[29] AER, *Transgrid Transmission Determination 2023 to 2028*, September 2022, https://www.aer.gov.au/system/files/AER%20-%20Transgrid%202023-28%20-%20Draft%20Decision%20-%20Attachment%204%20-%20Regulatory%20depreciation%20-%20September%202022.pdf

Synchronous condenser flywheels to maintain a stable voltage waveform

A key aspect of Transgrid's efficient level system strength obligation is to maintain a stable voltage waveform, which requires the ability to effectively damp voltage oscillations. Transgrid's detailed network planning studies have concluded that inertia is integral to adequately damp voltage oscillations, and therefore is integral to providing stable voltage waveform support.

Transgrid conducted power system modelling to optimise the quantity of inertia synchronous condensers are to provide for stable voltage waveform support.

The AER 'efficient management of system strength framework guidance note'[30] 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.

Non-network synchronous condensers

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

These synchronous condensers were proposed as a new build solution, which means that the entire cost to commission and operate was incorporated into the market modelling (i.e. treated the same as network synchronous condensers). The key costs including capex, fixed operations and maintenance and variable operations and maintenance were all provided by the proponent.

Committed and anticipated synchronous condensers: Project Energy Connect

Four synchronous condensers in total are to be installed on the Buronga and Dinawan substations as part of Project Energy Connect (PEC). These four synchronous condensers are committed projects and are modelled with fixed in-service dates provided by Transgrid.

Committed and anticipated synchronous condensers: Central West Orana REZ

Synchronous condensers owned and operated by ACEREZ (as the Network Operator) which are to be located within the Central West Orana (CWO) REZ are represented separately to other Transgrid synchronous condensers.

This reflects EnergyCo electing to have ACEREZ, the appointed network operator for the CWO REZ, centrally procure system strength for the first 5.84 GW of the CWO REZ. These solutions are modelled as committed projects with a fixed commencement of operations date.

These synchronous condensers were sized to meet the system strength requirements of the 5.84 GW of IBRs in the REZ. Their provision of system strength to other system strength nodes is also considered.

Since the PADR, the delivery timing of the ACEREZ synchronous condensers used to remediate Stage 1 of the CWO REZ has been revised. The updated timing was provided by EnergyCo in April 2025, which was insufficient time to incorporate within the fault level coefficient validation stage. The revised timing was captured in the PLEXOS modelling through updates in the coefficients which is discussed in section 4.2.2.

3.3.2 Non-network synchronous machines

Existing, committed and anticipated synchronous machines

The portfolio optimisation and market dispatch modelling considers various types of existing, and committed and anticipated synchronous machines, presented in Table 7.

The methodology to assign system strength contributions to each unit is discussed in Section 4.1.

Table 7. Overview of assumptions used when modelling existing, committed and anticipated synchronous machines

Technology	Assumptions
Existing, committed and anticipated synchronous plant without the ability to run in synchronous condenser mode	**Coal:** With the exception of Eraring, all NSW coal assets are modelled with fixed retirement dates aligned to the 2024 Final ISP Step Change scenario. Eraring's closure was updated to reflect its delayed retirement in August 2027 as per the agreement between Origin and the NSW State government . **Hydro and PHES**: Inflows and storage volumes and hydro plant technical parameters assumptions are consistent with AEMO's 2024 Final ISP Step Change scenario.
Existing, committed and anticipated synchronous plant with the ability to run in synchronous condenser mode	A subset of the existing hydro and pumped hydro assets in NSW have the capability to operate in synchronous condenser mode. Mutual exclusivity constraints were fitted to ensure the solution could only operate in synchronous condenser mode when not pumping or generating.
Existing synchronous plant which requires upgrades to run in synchronous condenser mode	Owners of several synchronous machines in NSW submitted EOI's to Transgrid to upgrade their plant to enable operation in synchronous condenser mode. The associated build cost to upgrade each unit must be incurred for the upgrade to be included in a Portfolio Option. Site-specific costings, technical constraints and techno-economic parameters were included based on EOI response data. If such upgrades are selected within the portfolio optimisation process, it does not disrupt the ability of the system strength solution to participate in the energy market beyond a mutual exclusivity constraint which ensures operation in generation and synchronous condenser mode does not occur simultaneously

New-build synchronous machines

Non-network, synchronous new-build solutions include various technologies capable of providing system strength. For gas and biomass plants, system strength can be provided when these solutions are operating at or above their minimum stable generation level. Pumped hydro also contributes to system strength when they are generating, pumping, or operating in synchronous condenser mode if this functionality is available. As these are not existing, committed or anticipated projects, their full build costs, as well as their operating costs, are incurred upon the selection of the unit in the optimised portfolio. As these technologies can also generate electricity, alongside the provision of system strength, and are not present in the Base Case, they may reduce the total cost of generation to satisfy electricity demand in some periods.

3.3.3 Batteries

This section provides an overview of the capex and timing assumptions for grid-forming (GFM) batteries, and grid-following batteries with the option to upgrade to grid-forming, noting that a battery requires a grid-forming inverter to provide system strength.

Four different categories of batteries were considered as candidates for system strength services:

- BESS with committed or anticipated status which submitted an EOI
- BESS that have not achieved committed or anticipated status but submitted an EOI
- ISP 'modelled' BESS, converted to grid-forming i.e. non-project specific BESS capacity included in the ISP Step Change equivalent scenario capacity development pathway
- 'Targeted' network or non-network grid-forming BESS.

A description of these categories and an overview of the capex and timing assumptions for each category is provided in Table 8.

Table 8. Overview of assumptions used when modelling batteries

BESS Category	CAPEX & timing Assumption	Rationale
EOI BESS with Committed or Anticipated Status (grid-forming BESS projects or grid-following BESS projects with the potential to upgrade to grid-forming)	**Contractual commitment with a grid-forming inverter**	
	No build cost or assumed contracting lag	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), it is assumed the grid-forming component of their project is "committed" for the purpose of the RIT-T, and hence there is no build cost associated with system strength provision for these projects. There is, therefore, no lag (or delay) in contracting with this plant, i.e. it can be contracted to provide system strength starting from its COD.
	No existing contractual commitment with a grid-forming inverter	
	1% incremental capex cost to enable grid-forming mode with a 12-month lag in contracting.	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). 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

BESS Category	CAPEX & timing Assumption	Rationale
		anticipated/committed projects which have a contractual commitment to connect in grid-forming mode were assumed to have no additional costs.
EOI BESS that have not reached Committed or Anticipated status	Full project capex as per AEMO 2023 IASR plus 5% incremental cost to upgrade to grid-forming and no timing lag.	New build batteries are modelled with the full grid-forming build cost and with the specifications outlined in each individual proponent's submission information. Capex assumptions for these projects are sourced from AEMO's 2023 IASR. AEMO's Final 2024 ISP capacity outlook does not explicitly distinguish between grid-following and grid-forming inverters, and all IBR are effectively treated as grid-following.[31] It is assumed that upgrades required to convert to grid-forming incur an additional cost equivalent to 5% of the upfront capital costs of the grid-following BESS. This incremental cost reflects the additional effort in the connection application process and the possible need for additional inverter capacity. That is, the cost of these projects is modelled as the 2023 IASR costs plus 5%. We assume that these projects will be commissioned in grid-forming mode from day one (i.e. it will be a condition of the non-network system security contract).
ISP 'modelled' Step Change BESS, converted to grid-forming (do not have an explicit non-network proponent)	Only 5% incremental capex to upgrade to grid-forming and no timing lag.	For these projects, only the 5% incremental capex cost to upgrade from grid-following to grid-forming inverters is applied, as the full capex of these projects is considered 'sunk' in the modelling Base Case. 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. We assume that these projects will be commissioned in grid-forming mode from day one (i.e. it will be a condition of the non-network system security contract.
'Targeted' grid-forming BESS (network or non-network)	Full BESS capex as per AEMO 2023 IASR plus 5% incremental cost to upgrade to grid-forming.	The options for the size, location and timing of deployment for 'Targeted' BESS are optimised within the portfolio optimisation model. 'Targeted' grid-forming BESS face the full build and connection costs associated with new entrant build, using IASR assumptions plus a 5% uplift, which is consistent with EOI BESS that are not committed or anticipated.

Further detail on the technical assessment of grid-forming batteries to provide system strength services and the representation of system strength provision in the modelling is provided in Section 4.1 and Section 4.2, respectively.

3.4 Asset specific inputs and assumptions

Third-party respondents to Transgrid's EOI for system strength services were asked to provide technical and cost information for their projects. Where appropriate, this technical and cost information was used for increased accuracy. If the required technical parameters were not provided

[31] P. 11 , AEMO, *2023 System Strength Report*, December 2023, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

by asset proponents, IASR 2023 values or assumptions from other sources were used. Table 9, Table 10 and Table 11 present the information requested from proponents through the EOI process.

Table 9. Project technical details requested

Information requested from proponent	Description
Project details	Details of equipment, including multiple units if appropriate, and any other relevant information describing the solution such as ability to operate in synchronous condenser mode (for hydro plants)
Rated Capacity (MVA)	Rated capacity of the solution in MVA (also clarify unit ratings and number of units if applicable)
Rated Capacity (MW)	Rated capacity of the solution in MW (also clarify unit ratings and number of units if applicable)
Storage duration (MWh)	Rated capacity of the solution in MWh
Minimum stable operating level (MW)	If the solution is a synchronous generating unit(s), the minimum stable operating level of each unit in MW
Solution Efficiency (%)	Round trip efficiency (applicable to BESS) and pumping efficiency (applicable to pumped hydro), using same definition as IASR
Auxiliary Losses (% or MW)	Auxiliary load / losses
Heat Rate (GJ/MWh)	The amount of energy used by an electrical generator/power plant to generate one megawatt hour (MWh) of electricity.

Table 10. Availability and activation details requested

Information requested from proponent	Description
Startup time (h)	Expected time following a dispatch or enablement instruction for the solution to synchronise to the grid and commence providing contracted system strength services
Forced outage duration (% or h of year)	Station-level forced outage rate, using same definitions as the latest IASR
Annual maintenance duration (% or h of year)	Duration of a year in which the solution would be offline for maintenance (represented in hours or a percentage, using same definitions as the latest IASR)
Project commissioning date	Expected date for a proposed new project to have completed construction, grid connection, testing and all commissioning activities and be available to provide the proposed system strength service
Service start date	Earliest feasible start date (month and year) for providing the system strength service to Transgrid.

Table 11. Economic details requested

Information requested from proponent	Description
Project CAPEX ($)	Total capital cost (regardless of ownership) of all assets required to deliver the system strength service that are not already existing or committed, including costs of plant/equipment, land, civil works, grid connection assets and development costs.
Fixed Operating Costs ($/kW/year)	Annual fixed operation and maintenance (FOM) costs of assets that are not already existing or committed - $/unit/year, $/kW/year, or $/year (for total solution).
Variable operating costs ($/MWh)	Expected variable operations and maintenance (VOM) costs of the solution.
Project status	The status of the project according to the five criteria for a committed project defined in the RIT-T[32]: Consents, construction, land, EPC contracts and finance.
Startup costs ($/startup/unit)	Expected costs that would be incurred each time a solution starts up to provide energy and/or system strength.
Fuel Cost ($/GJ)	Projection of future fuel costs for each year.

[32] AER - Regulatory Investment Test for Transmission instrument - 2024 - Version 3, p10. https://www.aer.gov.au/system/files/2025-05/AER%20-%20Regulatory%20Investment%20Test%20for%20Transmission%20instrument%20-%202024%20-%20Version%203..pdf

4 System strength representation

Transgrid as a System Strength Service Provider is required, under Clause S5.1.14 of the NER, to use reasonable endeavours to plan, design, maintain and operate its transmission network, or make system strength services available to AEMO. These services must 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.

Transgrid's system strength obligations are represented as constraints in Baringa's market modelling. The constraints are formulated to ensure that the system strength requirements were met in every time interval over the modelled horizon where feasible. These requirements are modelled as two sets of constraints:

1. Minimum level system strength constraints – implemented to meet minimum fault level requirements at each of the six declared system strength nodes in NSW.
2. Efficient level system strength constraints – implemented to facilitate the stable voltage waveform of new inverter-based resources at each of the six declared system strength nodes in NSW and at the forecast point of connection of future IBRS (using Available Fault Level as the proxy for stable voltage waveform).

The formulation of these constraint equations is illustrated in Figure 15. The components can be separated into the Left-Hand Side (LHS), Operator and Right-Hand Side (RHS).

Figure 15. Formulation of the system strength constraint equations

System strength constraint LHS

The LHS of the constraint equation represents the contribution of system strength from system strength solutions to a given node. The contribution is dependent on the "fault level coefficient" of each system strength solution, and for synchronous machines, is also dependent on the unit commitment of the solution.

Fault level coefficients towards each node are determined for all system strength solutions, varying by financial year. This includes coal, gas, hydro, pumped hydro generators, grid-forming batteries and synchronous condensers. For multi-unit power stations, coefficients vary depending on the number of units online, as the fault level contribution per unit decreases when more units are generating simultaneously.

The LHS is dependent on variables optimised in Baringa's portfolio optimisation and market dispatch modelling. For solutions that are synchronous generators, the unit commitment of each solution is optimised under both the portfolio optimisation and market dispatch modelling. Under the portfolio optimisation, the build decision for each new build system strength solution is optimised.

Detail on how the fault level coefficient factors for the LHS are determined and the technical feasibility of grid-forming batteries to provide system strength is provided in Section 4.1.

System strength constraint RHS

The calculation of the minimum and efficient level system strength requirements for the RHS is set out in Section 4.2.1 and Section 4.2.2. In calculating these requirements, Transgrid consider additional factors which impact the level of system strength services required, and quantify these factors through power system modelling in PSS®E. These components include the impact of:

- The largest credible contingency;
- Critical planned transmission line outages;
- Interstate contributions (which are reflected as a reduction in the requirement);
- planned maintenance of network synchronous condensers.

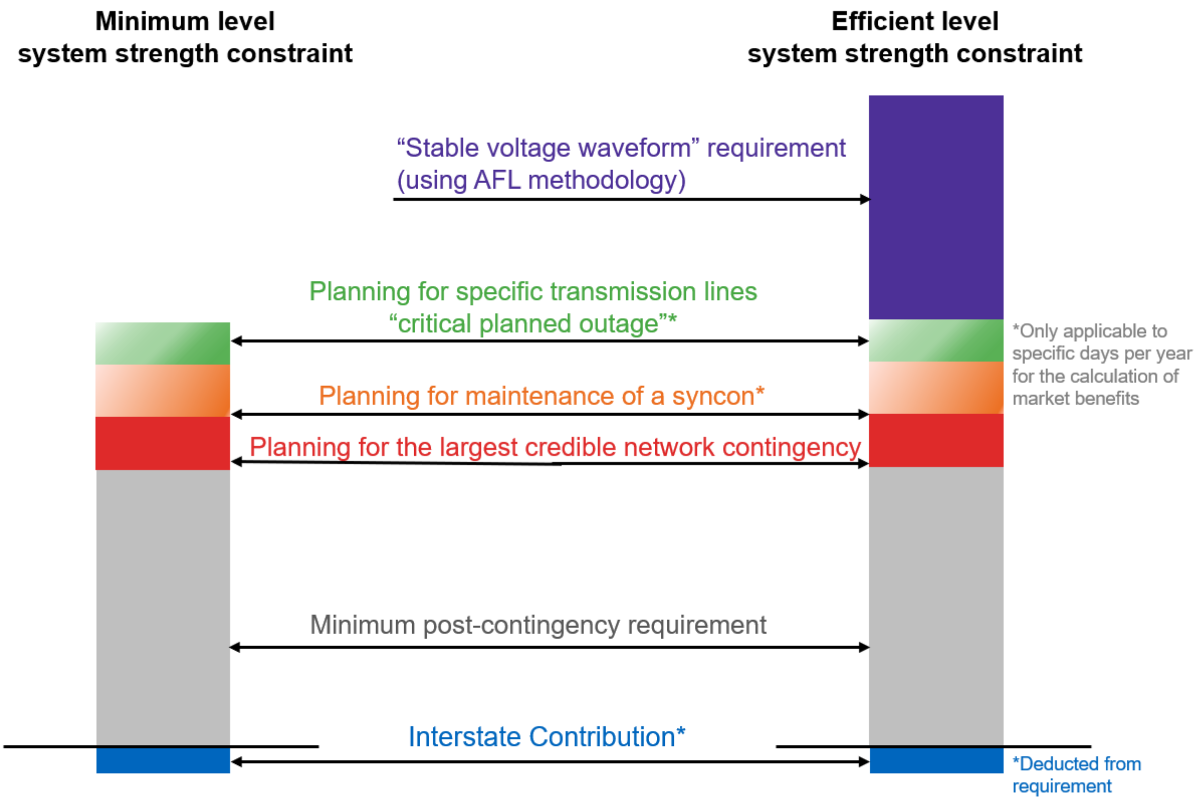
The components of the RHS of each constraint are shown in Figure 16. Formulation of the RHS of the system strength constraints The critical planned outage component is only applicable in specific periods where planned outages of critical lines are assumed to occur (several days per year). Network synchronous condenser maintenance periods are also limited to specific timeframes, based on assumptions about when maintenance for each unit is expected to take place. Additional detail on the factors considered in quantifying each component is provided in Section 4.2.3.

System strength constraint operator

The constraints are formulated such that the value of the LHS of the constraint must be greater than or equal to the value of the RHS. This means that the aggregate contribution of system strength from system strength solutions must be greater than or equal to the requirements for system strength at each system strength node. If this condition is satisfied, then Transgrid's system strength obligations are assumed to be met (and this is subsequently validated through power system modelling).

These controllable variables are optimised in the PLEXOS market model so that the aggregate of their fault level contribution is greater than or equal to the minimum and efficient level system strength requirements as set out in the RHS in all time intervals, where feasible.

Figure 16. Formulation of the RHS of the system strength constraints



4.1 LHS – Contribution of system strength solutions

Section 4.1.1 provides detail on the characteristics of system strength and how the fault level contribution of each system strength solution is determined. This is used to calculate the system strength contribution of each system strength solution to each node across the modelled horizon.

Section 0 outlines the technical feasibility of grid-forming batteries to provide system strength services and Section 4.1.3 provides detail on how the system strength contribution of batteries are determined, including the operational requirements and the fault level and stable voltage waveform contribution factors.

4.1.1 Fault level contribution of system strength solutions

This section provides an overview of the dynamic and non-linear characteristics of system strength and how it impacts the fault current contribution of system strength solutions. Baringa and Transgrid developed a methodology to calculate "fault level coefficients" for each system strength solution, towards each node in each financial year. This approach captured dynamic coefficients for coal and hydro power stations with multiple units which varied depending on the number of units online, and static coefficients for all other system strength solutions. This methodology is described throughout this section.

Calculation of system strength coefficients

The fault level coefficients assigned to each system strength solution in Baringa's market modelling are derived from detailed engineering analysis and power system behaviour. Their purpose is to quantify each solution's contribution to meeting the minimum and efficient level system strength requirement at the six NSW system strength nodes.

As outlined in Section 2.4.2 and Section 2.4.4, these coefficients were initially derived in PSS®E and iteratively refined through feedback between the PSS®E and PLEXOS models. This section explains the physical and operational dynamics that underpin the way these coefficients were calculated and calibrated.

System strength is inherently non-linear and highly sensitive to network operating conditions. A solution's contribution to fault level at a node is influenced by:

- Static characteristics such as size, location and technical design of solutions.
- Dynamic conditions like network topology, network impedance, and the operational status of other synchronous machines.

To capture these factors, a unique set of static fault level coefficients was calculated that vary by:

- Solution**,** to account for fixed attributes like location and technology type.
- Year, to reflect expected changes in the transmission network and synchronous generator fleet

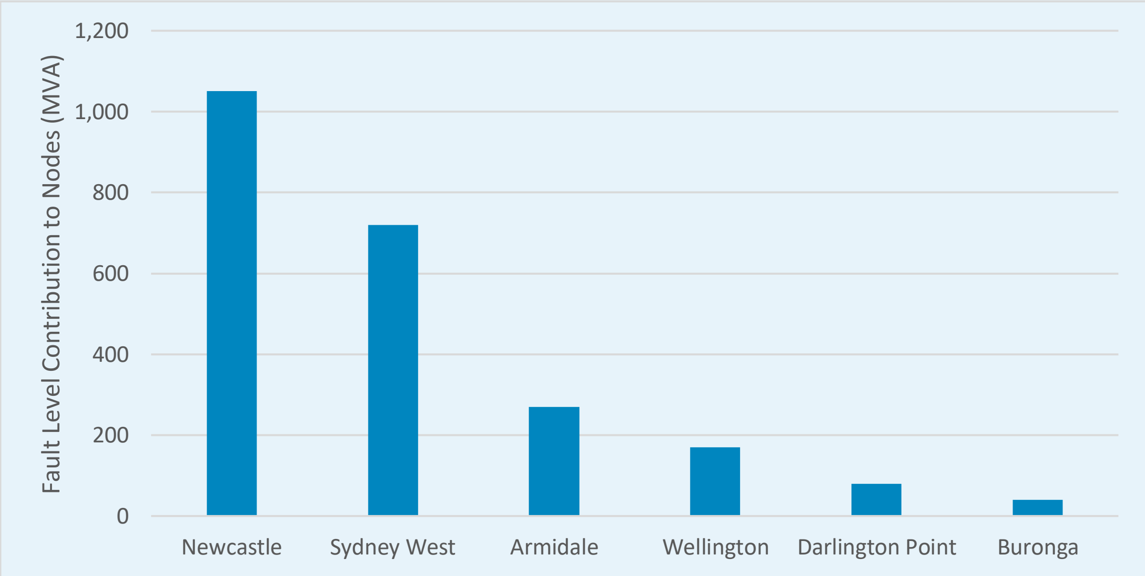
Dispatch interval variation in system strength coefficients was deliberately excluded to ensure the model remained tractable without introducing complexity. This simplification has no material impact on model outcomes, as the coefficients were calibrated to reflect fault level behaviour during low system strength periods (as described in Section 2.4.4) – where system strength gaps are most likely to occur. This targeted tuning avoids under-provision of system strength, which could risk system reliability, while also minimising over-provision that would lead to inefficient investment. As a result, the simplification preserves the accuracy of model outcomes.

The remainder of this section explains various factors that affect each solution's fault current provision in more detail, and how they are accounted for in the fault level coefficients.

Location of the system strength solution

The fault current contribution of a system strength solution diminishes as the electrical distance to the system strength node increases. Solutions located further from a system strength node contribute less due to higher network impedance along the transmission pathway. This effect is illustrated by the PSS®E modelled outcomes in Figure 17, which shows the fault level contribution of a synchronous condenser located at Newcastle to the six defined system strength nodes in NSW. The fault current contribution of the synchronous condenser decreases at nodes which are electrically further from Newcastle.

Figure 17. Fault level contribution of a synchronous condenser located at Newcastle to all NSW system strength nodes[33]



Total synchronous machines online in NSW – the 'global' effect

The fault level contribution of a given solution also varies based on how many other synchronous machines are online. As more synchronous machines operate across NSW, the system fault level increases, and the relative contribution of each individual unit decreases - particularly towards electrically remote nodes. This is because the total rated capacity of synchronous machines online in NSW is a proxy for fault level at system strength nodes, and as the fault level at a system strength node increases, network impedance plays a greater role in determining how much fault current can flow to that node[34].

The figure below demonstrates the fault level contribution for a synchronous condenser located at Newcastle. The key points to note are:

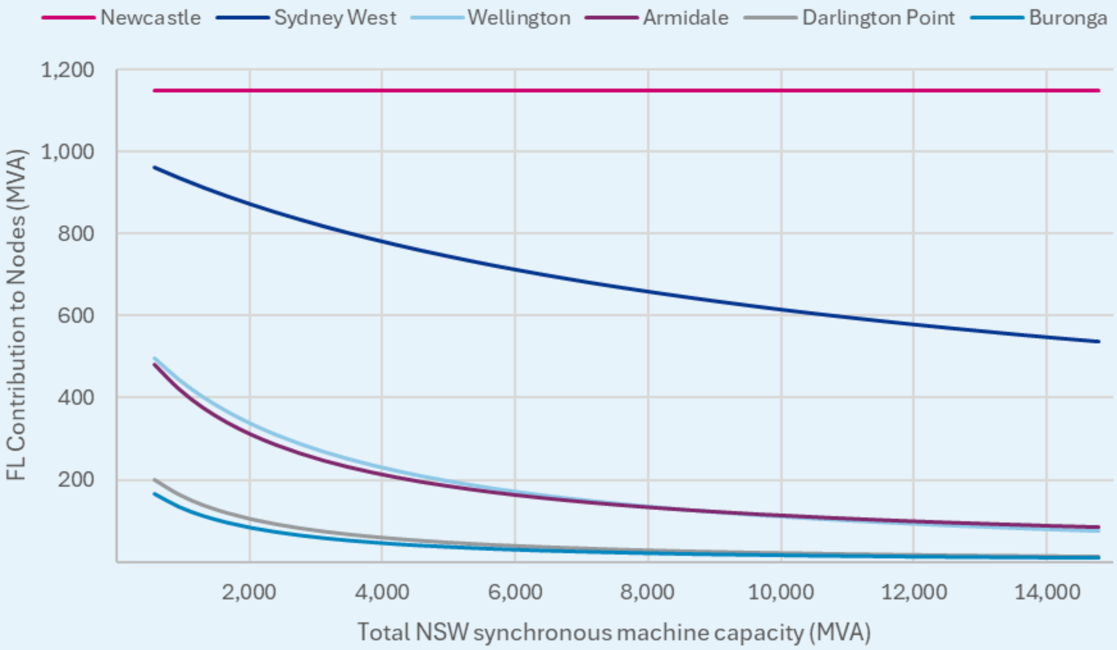
- There is no change in fault level contribution at Newcastle, the point where the synchronous condenser is connected, because the fault current provision from the synchronous condenser to its point of connection remains the same irrespective of the status of other generators.
- Network impedance influences the contributions to other system strength nodes, with higher impedance reducing the contribution.

[33] Average fault level contribution during the lowest 30th percentile of NSW fault current periods in 2029/30

[34] In addition to the network impedance, the current injected by a generator during a fault is a function of the generator's bus voltage under the fault condition, which, in turn, is dependent on the network's configuration and the status of other generators. With more generators online in the system, the voltage change seen at the generator terminals during a fault will be lesser and hence the current injection which is proportional to this voltage deviation will be lower.

- The fault level contribution of the Newcastle synchronous condenser decreases at all other nodes as more synchronous machines come online across NSW. This effect is non-linear, i.e. the lines are curved.

Figure 18. Contribution of a synchronous condenser at Newcastle to the NSW system strength nodes (in 2029/30)[35]



Fault level at the solution's point of connection – the 'localised' effect

For coal and hydro solutions with multiple units, the modelled fault level contributions per unit decline as additional units at the same location are dispatched simultaneously. This is due to the high local fault level at the point of connection, which increases the impedance 'seen' by each additional unit. This local saturation effect was significant enough to warrant a more granular treatment for coal and hydro power stations which typically have multiple units at the same point of connection. PSS®E was used to model over 4,000 coal unit combinations and 24,000 hydro unit combinations. Using this dataset, Baringa developed dynamic coefficients that vary with the number of units online at a given power station, preserving this localised behaviour in the Baringa market modelling.

This localised effect can be observed in Figure 19, which shows the variation in the average system strength contribution of a single coal unit as other units of the same generator come online. As additional units at the same power station come online, the effectiveness of each individual unit decreases. The fault level contribution of the individual unit is lowest when all four units are online at the same time.

[35] This example is illustrative and does not capture all updated input assumptions used in PACR modelling.

Figure 19. Fault level contribution of a single coal unit to the Newcastle system strength node as the number of units online at the power station varies[36]

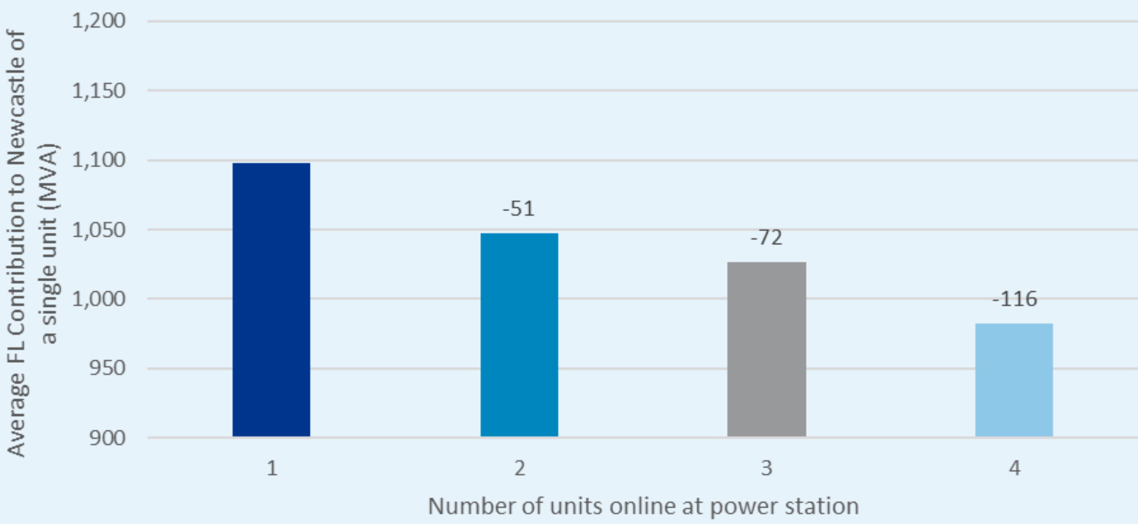
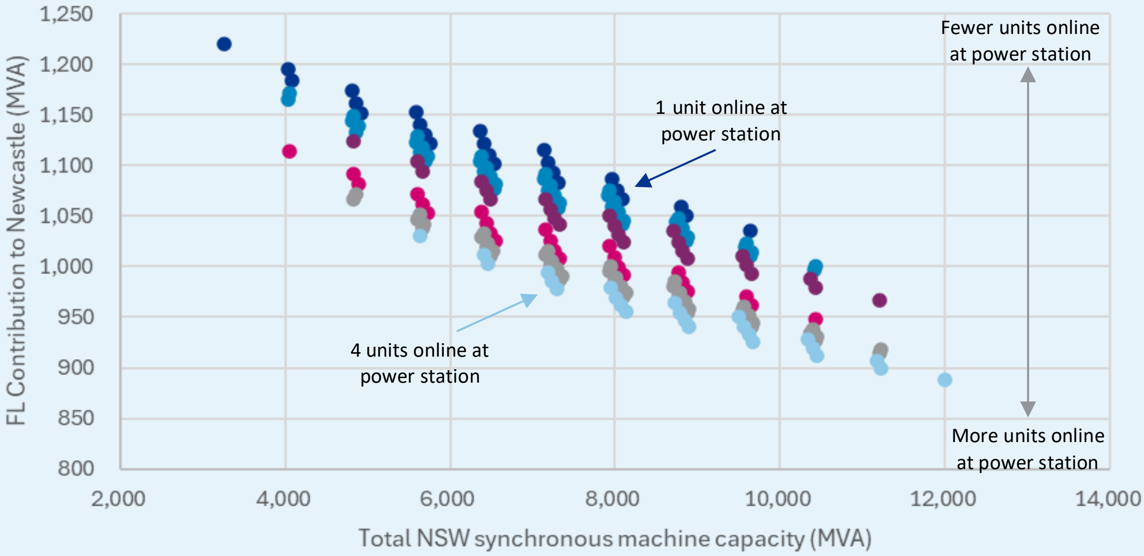


Figure 20 illustrates how both the number of units online at a power station (the 'local' effect) and the level of synchronous machine capacity online across the broader network (the ‘global’ effect) influence the fault level contribution of a single coal unit. The contribution of an individual coal unit to the Newcastle node decreases as more units at the same power station are brought online and as total synchronous capacity across NSW increases.

[36] This example is illustrative and does not capture all updated input assumptions used in PACR modelling.

Figure 20. **Fault level contribution of a single coal unit to Newcastle system strength node as both the number of units online at the power station and the NSW online synchronous machine capacity varies (2025/26)**[37]



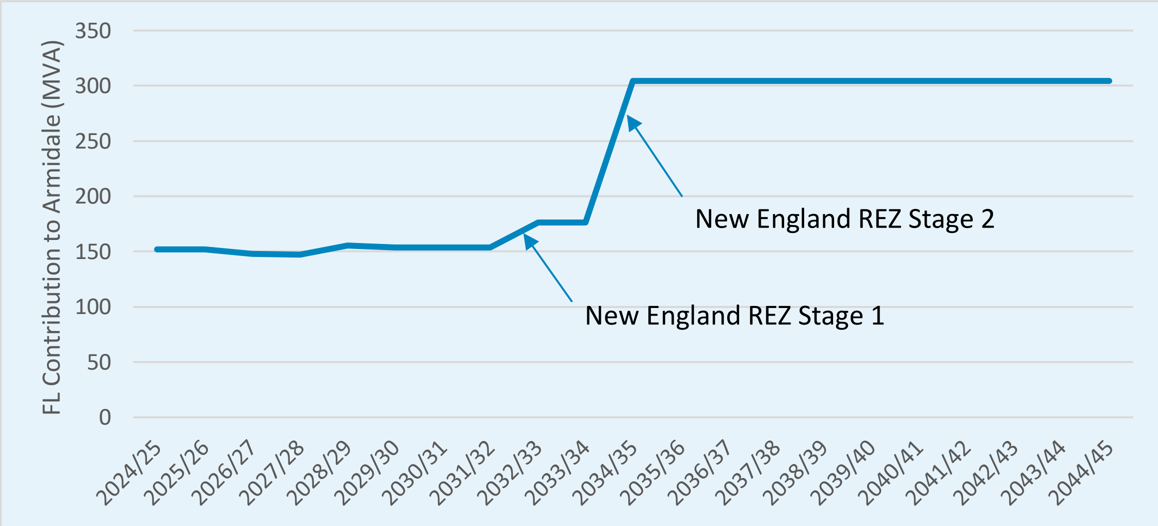
Transmission network augmentations

Transmission network augmentations cause step changes in some solutions' fault level coefficients. For example, the New England REZ transmission project will significantly reduce the network impedance between Newcastle and Armidale. As a result, fault level contributions to Armidale from a synchronous condenser at Newcastle will significantly increase following the commissioning of Stages 1 and 2 of the New England REZ transmission link.

Figure 21 depicts the fault level contribution of a Newcastle synchronous condenser to Armidale increases in 2032/33 following the completion of the New England REZ Stage 1 transmission link and in 2034/35 following the completion of the New England REZ Stage 2 transmission link.

[37] This example is illustrative and does not capture all updated input assumptions used in PACR modelling.

Figure 21. Illustrative example of fault level contribution of a Newcastle synchronous condenser to Armidale over time.



Calculation of fault level coefficients

Fault level coefficients were calculated and assigned to all synchronous machines such as coal, gas, hydro and pumped hydro, and network solutions such as synchronous condensers.

Section 2.4.2 and Section 2.4.4 describe how Transgrid and Baringa calculate and tune the static fault level coefficients, to accurately represent provision of the minimum level and efficient level of system strength in Baringa's market modelling, without needing to vary the coefficients for each dispatch interval to account for short-term variations due to network outages or dispatch outcomes.

The static coefficients are calibrated based on the modelled timestamps which correspond to an average of the bottom 30% in each year. This ensures that the periods which are most at risk of system strength gaps are modelled accurately. Conversely, in periods where there are many online synchronous units and high levels of available fault level current, the use of static coefficients results in the calculated fault level current being overstated. This does not have an impact on the modelled outcomes since there were already high levels of fault current in the system and no additional solutions are required to come online to provide additional system strength.

Fault level coefficients were also calculated for grid-forming batteries. Detail on this is provided in Section 4.1.3.

4.1.2 Technical assessment of the maturity of grid-forming batteries for system strength services

This section describes the treatment of grid-forming batteries towards meeting system strength requirements.

Technical maturity of grid-forming batteries

Grid-forming batteries hold significant potential to co-optimise system strength provision with other market benefits. However, grid-forming batteries and grid-forming inverter technologies are relatively novel and have not yet been deployed at significant scale. As part of completing this RIT-T, Transgrid engaged Aurecon to undertake an assessment of the technical maturity of grid-forming batteries to provide system strength support. The findings of this assessment and the impact on the treatment of batteries in the modelling are discussed throughout this section.

Minimum fault level requirements

Minimum three phase fault level requirements are critical for power system security (S5.1a.9), to enable:

- correct operation of protection systems of networks and Network Users (both transmission and distribution)
- stable voltage control systems; and
- the power system to remain stable following any credible contingency event or protected event.

This is consistent with advice from AEMO's Transition Plan for System Security[38] published in December 2024 which 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 [39].

Aurecon's assessment concluded[40] that there is insufficient evidence (either at-scale deployments or in modelling) to rely on grid-forming batteries to support minimum fault level requirements (until 2032/33), 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

[38] AEMO, *2024 Transition Plan for System Security*, December 2024, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

[39] AEMO, *Update to the 2023 Electricity Statement of Opportunities*, May 2024, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/may-2024-update-to-the-2023-electricity-statement-of-opportunities.pdf

[40] Aurecon, *Advice on the maturity of grid-forming inverter solutions for system strength*, April 2024. This report was been released alongside the PADR.

- the performance and stability of grid-forming batteries 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.[41]

Based on AEMO and Aurecon's assessment, grid-forming batteries have been excluded from contributing to the minimum fault level requirements in Transgrid's PACR market modelling until 2032/33.

Grid-forming batteries will only be considered capable of supporting minimum fault level requirements when further assessments and mitigation measures are in place. This phased approach is designed to balance the deployment of grid-forming technology while managing the associated risks in the grid.

Stable voltage waveform

Aurecon concluded that grid-forming batteries are sufficiently mature to provide stable voltage waveform support to the connection of new IBRs up to a maximum of 50% of the efficient level solution size. This limit aims at striking a balance between:

- a sizeable deployment of grid-forming batteries;
- minimising the risk of unknowns; and
- avoiding the frequent curtailment of grid-following IBR in practice.

Transgrid has not explicitly applied Aurecon's recommended 50% 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, Transgrid observed this limit being breached in regions that have low efficient level requirements, but high minimum level requirements, for example surrounding Newcastle and Sydney West. 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.

Summary

The assumptions adopted for the PACR modelling are based on the advice provided by Aurecon on the technical feasibility of grid-forming batteries to provide system strength services and are summarised in Table 12.

Table 12. Grid-forming BESS modelling assumptions

Requirement	Constraint	Modelled assumption guided by Aurecon advice
Minimum three phase fault level	Minimum fault level requirement	Grid-forming BESS can provide up to 100% of this requirement *from* 2032/2033. Grid-forming BESS cannot

[41] 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.

		contribute to the minimum fault level requirement until this time.
Stable voltage waveform	Efficient level requirement	Grid-forming BESS can provide system strength services to meet this requirement from 2025/26. [42]

4.1.3 Modelling the contribution of grid-forming batteries for system strength services

In the PACR, Transgrid refined it's modelling of grid-forming BESS to more accurately reflect their contribution to the efficient level. The PADR that assumed all grid-forming batteries provide the same amount of system strength (per MVA of inverter capacity) and are equally as effective at remediating IBR; the PACR differentiated the performance of each BESS by their inverter OEM. This was implemented in Baringa's market modelling as a static coefficient that does not vary with the battery's dispatch.

Separate coefficients are applied in the minimum and efficient level constraints to represent the different contribution of batteries towards minimum fault level requirements and stable voltage waveform support. Note that for the system strength portfolio model optimisation process, batteries are considered to contribute solely to the efficient fault level constraints until 2032/33 as detailed in Section 4.1.2. Past this, BESS are assumed to contribute to minimum fault level requirements, albeit without a "boost factor", as described below.

Contribution to minimum fault level requirements

Grid-forming batteries are typically limited in their ability to provide fault current, with overload limits varying depending on the inverter OEM. In this modelling, an overload current range of 1.26 to 1.34 per unit was applied based on the inverter technology used by each solution. Accordingly, from 2032/33 onwards, each 1 MW of grid-forming battery capacity is assumed to contribute 1.26 to 1.34 MVA of fault current at its point of connection.

Contribution for stable voltage waveform support

Transgrid recognises that fault current is only a proxy for the provision of stable voltage waveform support and that grid-forming batteries are disadvantaged for contributing to stable voltage waveform when assessed using the AFL method due to the technologies limited overload capabilities. Power system studies undertaken by Transgrid and others in the industry show 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).

Transgrid used a 'boost factor' to account for the disadvantage that grid-forming batteries face when stable voltage waveform support is 'valued' using solely the AFL method. The boost factor was calculated via PSCAD™, using individual OEM-supplied inverter models and focused solely on

[42] Aurecon, *Advice on the maturity of grid-forming inverter solutions for system strength*, April 2024, https://www.transgrid.com.au/media/diyb5fng/2403-aurecon_maturity-of-grid-forming-inverter-solutions-for-system-strength.pdf

the ability of a solution to maintain stable voltage waveform, without consideration of transient behaviour.

The studies involved different aggregates of IBRs and determining the synchronous condenser size that would allow the IBR to maintain stable voltage waveform. The synchronous condenser was subsequently removed and replaced with a grid-forming battery, which was sized until the IBR aggregate achieved the stable voltage waveform criteria. Results varied depending on the inverter supplier: while some inverters required between 126 MVA and 200 MVA of BESS capacity to match the performance of a 100 MVA synchronous condenser, two inverter models were found to be incapable of providing any stable voltage waveform support. Based on this analysis, boost factors ranging from 2.6 to 4.1 were calculated and applied in the PACR modelling, depending on the inverter technology. An example of this calculation is provided below.

For the highest-performing inverter, a 1.26:1 BESS-to-synchronous condenser ratio was established. In Transgrid's power system modelling, a 200 MVA synchronous condenser is assumed to provide 1,050 MVA of fault current at its point of connection (i.e. 5.25 times its rated capacity). To achieve the same system strength benefit using grid-forming BESS, 254 MVA of BESS would be required—equating to a boost factor of 4.1 (1,050 MVA / 254 MVA). This value is applied in the PACR to accurately capture the effective contribution of high-performing grid-forming BESS technologies.

Application of efficient level coefficients

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 applied. This value reflects the lowest boost factor observed among the inverter technologies tested that could support stable voltage waveform. 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 soon. Applying the lowest effective boost factor ensures the modelling does not overstate the performance of unconfirmed technologies while still accounting for their likely contribution as capabilities improve.

For 'targeted' grid-forming BESS, which are modelled as the entire CAPEX cost, a boost factor of 4.1 was applied in the modelling, as we assume that BESS 'targeted' towards supporting system strength requirements as identified by this RIT-T would prioritise selection of a grid-informing inverter with the best performance in supporting stable voltage waveform.

High-level Electromagnetic Transient (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[43] 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.

[43] Electranet, *Contribution of GFM BESS for System Strength | Feasibility Assessment*, 2025

4.2 RHS – Transgrid's system strength requirements

Transgrid's system strength requirements were incorporated into Baringa's portfolio optimisation and market dispatch models as RHS values in the system strength constraints. This section describes how the obligations were determined and the methodology to calculate the requirements.

- Section 4.2.1 provides an overview of Transgrid's minimum fault level requirements.
- Section 4.2.2 provides an overview of Transgrid's efficient level obligations and the assumptions and the approach taken to calculate the requirements.
- Section 4.2.3 describes other components of the requirements such as N-1 contingency requirements, planned maintenance requirements, critical planned outage requirements and interstate contributions.

4.2.1 Minimum fault level requirements

AEMO's 2024 System Strength Report identifies six system strength nodes in NSW. The minimum fault level requirement is intended to be enough system strength to maintain overall system stability and ensure that network protection and voltage control devices can operate correctly.

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

AEMO has determined the minimum fault level requirements for NSW nodes as set out in Table 13.

Table 13. NSW minimum fault level requirements (Source: AEMO 2024 System Strength Report)

Node	System strength need (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

The modelling process has applied AEMO's post-contingency minimum fault level requirements as set out above for the entire portfolio formulation process. Transgrid has assessed N-1 contingencies separately to AEMO as discussed in Section 4.2.3.

4.2.2 Efficient level requirements / "Stable Voltage Waveform" requirements

Transgrid's efficient level obligation

Transgrid, as the NSW SSSP, has obligations under the National Electricity Rules to forward procure sufficient system strength services to support the stable connection and operation of the efficient level of IBR forecasts from 2 December 2025.

AEMO provides a 10-year forecast of the efficient level of IBRs in their annual System Strength Report, most recently published in December 2024, which sets Transgrid's system strength requirements. However, in the 2024 System Strength Report, AEMO updated its IBR forecast based on the Final 2024 ISP which did not incorporate the revised delivery schedule for the New England REZ. As this change is expected to be material to the timing and distribution of future IBR, Transgrid have opted to plan to an IBR forecast developed by Baringa. This IBR forecast is developed using the same modelling methodology used by AEMO to calculate the IBR forecast in its ISP and System Strength Report, however, incorporates the updated delivery timing of New England REZ. Further details are provided in section 3.1.2.

The approach to adapt IBR projections based on latest available information follows the 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."[44]

PACR market modelling assessed the efficient level requirement as a static requirement at each node, which changes as, per our obligations, on an annual basis, based on the nameplate capacity of the forecasted IBRs as shown in Section 3.1.2. However, due to limitations in the Available Fault Level proxy used to calculate the efficient level requirement, the system strength need in Hunter-Central Coast REZ was not accurately captured in the market model. To ensure this need is addressed, Transgrid modelled Hunter-Central Coast REZ outside the market model using PSCAD™. Further details on this are provided in Section 6.6.2 of Transgrid's Project Assessment Conclusion Report for system strength.

Consideration of IBR under the previous 'do no harm' rules

As part of the new system strength requirements, the current 'do no harm' rules evolve into the System Strength Mitigation Requirement (SSMR) where new connecting parties may opt into a system strength charge rather than self-remediate. While these new rules only apply to projects that have submitted a Connection Application after 15 March 2023, projects that fall under the old rules may opt into the new SSMR and pay the system strength charge rather than having to self-remediate.[45]

[44] P18. AEMO, *System Strength Report*, February 2025

[45] AEMC, *National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021*, Final Determination, October 2021,https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

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

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 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.

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).

Central West Orana REZ remediation

In early 2023, EnergyCo informed Transgrid that it planned to 'self-remediate' system strength for Stage 1 of the CWO REZ (5.84 GW of IBRs) through their own network build option. This will be implemented by 'ACEREZ'[46] as the CWO REZ Network Operator, rather than by Transgrid as NSW's SSSP. This was also stated in the NSW Government's May 2023 Network Infrastructure Strategy[47], was formalised in a letter from EnergyCo to Transgrid on 24 October 2023 and ACEREZ has now signed the commitment deed as the Network Operator for CWO REZ Stage 1. 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.

In line with conversations between SSSPs and AEMO during SSSP Working Group meetings, Transgrid proposes to use a 'true-up' methodology to 'true-up' AEMO's IBR forecasts to reduce Transgrid's obligations by the equivalent amount of IBRs (5.84 GW) from the region of the Wellington node that are projected to be remediated by ACEREZ. This 'true-up' will enable Transgrid to 'pass off' its obligations for the forward procurement of system strength services for specified IBRs/REZs.

ACEREZ and EnergyCo have advised Transgrid that seven synchronous condensers are planned for the self-remediation of the CWO REZ, with each synchronous condenser providing 834-955 MVA fault current at their point of connection. Transgrid and Baringa have modelled the

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

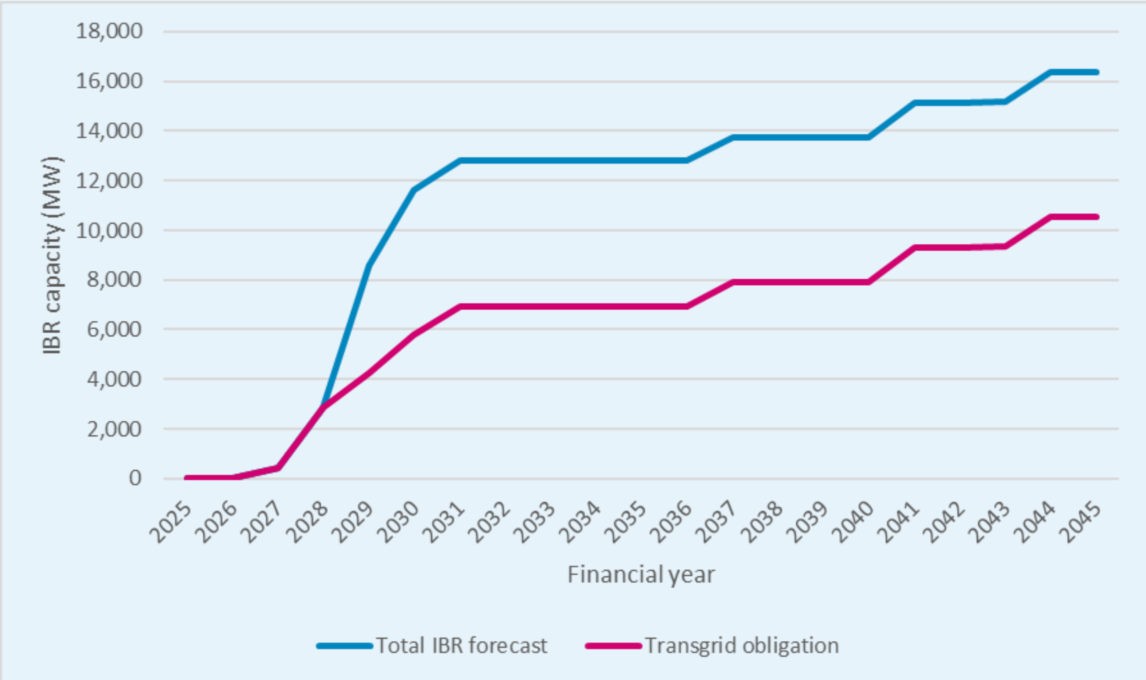
[47] System strength remediation for phase 1 of the CWO REZ (5.84 GW IBR capacity) is "included as part of the network build", which will be implemented by the REZ Network Operator. See: EnergyCo, *NSW Network Infrastructure Strategy - Appendix B: Network Infrastructure Options*, May 2023, p 4.

self-remediation of CWO REZ Stage 1 so that it has no net negative effect on system strength in the wider power system.

Note that while Transgrid has deducted CWO's 5.84 GW of IBRs from our 'obligations', both the CWO IBRs and the CWO synchronous condensers *are* included in the market modelling, as otherwise the supply-demand modelling would otherwise be affected. Therefore, the ACEREZ system strength remediation projects (i.e. 7 synchronous condensers) are included as modelled projects (locking it into the Base Case and all modelled options), to ensure that the supply-demand modelling can remain unaffected, and to ensure that no additional system strength remediation is required for the 5.84 GW of IBRs in CWO REZ.

Figure 22 shows the Wellington IBR forecast and the CWO REZ 'true-up' process for the 5.84 GW IBR forecast within CWO REZ Stage 1, commencing in 2027/28.

Figure 22. AEMO IBR forecast at the Wellington system strength node



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

Due to insufficient time to incorporate this advice within the fault level coefficient validation stage, further PSS®E analysis was undertaken by Transgrid to quantify the impact of delayed CWO REZ synchronous condensers on the system strength provision of all other synchronous units in NSW. This was done to capture the dynamic nature of system strength, which in general sees the individual fault level contribution of a given unit increase as the number of other synchronous machines online reduces. The difference between the loss in fault current and the dynamic response of existing synchronous machines node was added to the RHS of the minimum and efficient level system strength requirements for each respective system strength node during the impacted period.

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). In lieu of sufficient 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.

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.

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.

Transgrid also opted to conduct an out-of-model sensitivity using PSCAD™ to assess system strength solutions to remediate an IBR build-out consistent with the nameplate capacities of projects that have been awarded Access Rights and their timing is consistent with advice from EnergyCo. Further details are discussed in the PACR.

Effective Short Circuit Ratio (SCR) requirement

AEMO's System Strength Impact Assessment Guidelines (SSIAG) suggest that for future IBRs that have not undertaken a withstand assessment, an $SCR_{withstand}$ of 3.0 be used, with a stability coefficient (alpha factor, α) of 1.2. This stability coefficient indicates that the minimum SCR needed to maintain voltage stability without additional system strength or reactive power support is approximately 1.2, reflecting network limitations at the point of connection.

As such, Transgrid has applied this assumption to all planned IBR projects, except for the CWO REZ. For the CWO REZ, a $SCR_{withstand}$ of 2.34 was used to align the model with EnergyCo plans to remediate the IBR in the CWO REZ with seven 240 MVA-rated synchronous condensers.

Calculation of the efficient level requirement for use in PLEXOS

The efficient level requirement calculation methodology is based on the calculation of the AFL at connection points of AEMO's IBR forecast. To calculate the AFL, a power system Base Case was created in PSS®E which represents the future IBR forecast, as shown in Section 3.1.2 and the future transmission network, as defined in AEMO's 2024 ISP's Optimal Development Pathway, with updates to transmission timing as per public announcements.

The AFL is computed using the formula outlined in the SSIAG, as follows:

$$AFL = S_{SG} - \Delta$$

$$\Delta = S_{total} - S_{SG}$$

Where:

S_{SG} is the fault level at a bus with only synchronous machines online in the system; and

S_{total} is the fault level at a bus with both synchronous and asynchronous machines online.

The procedure to calculate the efficient level requirement is linked to the value of S_{SG} (the fault level at a bus with only synchronous machines online in the system) and the minimum fault level required at the system strength node.

The formula for the efficient level requirement is:

$$EFL = S_{SG} + |AFL| - [\text{minimum fault level requirement}]$$

4.2.3 Additional system strength planning requirements

This section describes the approach taken to incorporate N-1 contingency events, planned maintenance, critical planned outages of transmission lines and interstate fault level contribution into Transgrid's system strength requirements.

N-1 contingency requirement

N-1 contingency analysis evaluates the system's ability to withstand the credible loss of any single component whilst maintaining secure operation. N-1 conditions are accounted for in Baringa's market modelling by creating an N-1 contingency requirement at each node to represent the impact of network contingencies.

Using PSS®E, a N-1 contingency requirement is calculated by considering the largest reduction in fault level that occurs at each system strength node during an outage in the NSW transmission network. Only network contingencies are considered for this N-1 contingency requirement because coal generator contingencies are already accounted for in PLEXOS via 'unplanned outages'. This requirement is in addition to AEMO's post-contingency minimum requirement.

Planned maintenance requirement

All proposed system strength solutions require, to some extent, planned maintenance. Incorporation of scheduled maintenance periods into Baringa's market modelling better simulates real-world conditions and allows for a more accurate assessment of system strength levels in the future power system.

In the PACR modelling, synchronous condenser maintenance was incorporated to more accurately capture its impact on system strength. While each synchronous condenser has a defined fault level contribution to various nodes, the maintenance buffer was not set equal to this full contribution, as doing so would overstate the impact of a synchronous condenser being offline. This is because taking a synchronous condenser out of service reduces network impedance, allowing other synchronous machines to increase their fault level contribution to nearby nodes.

Instead, maintenance buffers were calculated based on the net reduction in fault level observed at each node when a synchronous condenser was removed from service. For example, while a Newcastle synchronous condenser may contribute 1,050 MVA of fault current to the Newcastle node, its removal results in only a 450 MVA drop in fault level, as other units respond to the change in network conditions. These maintenance buffers were calculated for all synchronous condensers, across all nodes, and for all years in the modelling period.

Synchronous condenser maintenance was not incorporated into the portfolio formation model but was considered during the portfolio validation process in PSS®E. Maintenance was then considered in the ST model where it was assumed to occur annually for each synchronous condenser, with outages applied to distinct periods, one machine at a time to avoid overlap. These outages were perfectly sequenced and scheduled outside of the shoulder seasons to minimise system strength impacts. This approach ensured that multiple synchronous condensers were not offline simultaneously, as overlapping maintenance would reduce the availability of synchronous machines to provide system strength support. This also represents an improvement over the PADR modelling, which applied maintenance buffers uniformly across all periods. Baringa also captured maintenance of generators through discrete periods where the units were offline and unavailable to provide energy or system strength according to assumed maintenance rates from AEMO's IASR. More detail on this methodology is provided in Section 3.2.

Critical planned outage requirements

The system strength rule change allows AEMO to account for critical planned transmission line outages in setting the minimum fault level requirements. AEMO has declared several critical planned transmission line outages in the 2024 System Strength Report which it expects SSSPs to incorporate into proposed system strength solutions on a case-by-case basis. These outages in NSW for each system strength node are outlined in Table 14.

Table 14. Critical planned outages in NSW for each system strength node

Affected system strength node	Network outage
Armidale Newcastle	83 Liddell to Muswellbrook 330 kV line 8E Armidale to Saphire 330 kV line 8J Saphire to Dumaresq 330 kV line 8C Armidale to Dumaresq 330 kV line 84 Liddell to Tamworth 330 kV line 88 Muswellbrook to Tamworth 330 kV line 85 Tamworth to Uralla 330 kV line 86 Tamworth to Armidale 330 kV line 8U Uralla to Armidale 330 kV line
Darlington Point	O51 Lower Tumut to Wagga Wagga 330 kV line 62 Jindera to Wagga Wagga 330 kV line 63 Wagga Wagga to Darlington Point 330 kV line X5 Darlington Point to Balranald 220 kV line O60 Jindera to Dederang 330 kV line
Newcastle	81 Liddell to Newcastle 330 kV line 82 Liddell to Tomago 330 kV line
Wellington[48]	79 Wollar West to Wellington 330kV line 72 Mt Piper to Wellington 330kV line

Transgrid undertook detailed fault level studies using PSS®E and built an optimisation model to calculate the additional system strength remediation required under planned outage conditions of each critical transmission line. These outages are inevitable for planned maintenance of transmission lines and for the connection of key transmission projects including New England REZ, VNI West and Hunter Transmission Project.

Transgrid has, therefore, considered the impact of these impending outages on their system strength requirements. Each outage was assessed to determine the additional system strength required at each node (in MVA fault current) to ensure minimum fault level requirements were maintained (compared to a case where the line was not out of service).

The additional system strength requirement during critical transmission line outages have been incorporated into Baringa's market modelling as a buffer applied to the RHS constraints, but only during periods when scheduled maintenance is assumed for each line. The timing and duration of these maintenance operations – typically less than 10 days per year – have been provided by Transgrid's maintenance planning team. This approach is conservative, as the connection and commissioning of new REZs in NSW will involve longer outages of certain lines in specific years.

[48] In an email to Transgrid in April 2025, AEMO confirmed that the outage of lines 79 or 72 represents a significant impact on fault levels at the Wellington node. AEMO advised that these outages meet the criteria for Critical Planned Outages under the System Strength Requirements Methodology and should be considered in the system strength PACR.

Interstate contribution of fault level

System strength is not confined by state boundaries, and some system strength flows naturally to NSW from other states. If Transgrid does not account for this interstate contribution, it risks over-procuring system strength within NSW, leading to higher costs for consumers.

In early 2023, Transgrid, AEMO and the other SSSPs agreed that join planning arrangements should be used to account for interstate system strength contributions when assessing the minimum level requirements. This means SSSPs can ’expect’ a certain level of fault current to flow from interstate.

To avoid a potential gap in system strength if each SSSP relies on each other for the ‘minimum’ amount of interstate system strength transfer, Transgrid has assessed it prudent to ‘derate’ the benefit coming from each state (beyond N-1).

Transgrid developed a methodology to calculate the amount of system strength that can be relied upon from other states, assuming they meet other SSSPs meet their minimum level obligations. Using detailed power system studies in PSS®E, Transgrid calculated the fault level contribution of each state towards NSW system strength nodes assuming each state operates the minimum number of synchronous machines required by AEMO’s “Transfer Limits Advice – System Strength” report, less one or two units as a de-rating (applied on a case-by-case basis).

5 Portfolio Option design

Baringa and Transgrid, as per the modelling methodology set out in Section 2, undertook portfolio optimisation under the core set of assumptions outlined in Section 2.5.6, and the representation of system strength described in Section 4.

Portfolio Option 1, derived through the portfolio optimisation process, represents a ‘just enough’ and ‘just-in-time’ approach. 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 is named the ‘basic portfolio’.

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 risks of future uncertainties.

In addition to Portfolio Option 2, Transgrid 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 with 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.

This chapter discusses the composition of the basic Portfolio Option in Section 5.1, the composition of the enhanced portfolio and the three manually adjusted Portfolio Options in Section 5.2 and the two portfolio composition sensitivities modelled within the PACR in Section 5.3.

5.1 Portfolio optimisation outcomes

Portfolio Option 1 was formed through the portfolio optimisation approach outlined in Section 2.4. This is consistent with a ‘least-cost’ optimisation approach, which has perfect foresight of future conditions. The deployment of system strength solutions is optimised to just meet the increasing minimum and efficient level system strength requirements as outlined in Section 4.2.

The portfolio optimisation model determines the least-cost generation and storage dispatch and system strength solution development plan for NSW, including:

- The dispatch of market participants, including synchronous machines which provide system strength services as a byproduct of their generation or consumption of electricity;
- The build path of new system strength solutions; and
- The build path of upgrades to existing, committed or anticipated solutions.

The build of new system strength solutions is primarily to replace retiring synchronous generators which reduces the provision of system strength associated with energy market dispatch, and to facilitate increasing capacities of IBR, which increase the efficient level requirements.

New-build system strength solutions have the capability of meeting system strength requirements at multiple nodes, and not just at the node of connection. The capability of meeting system strength needs at other nodes depends on the electrical impedance between the location of installation and the other nodes and is technology specific. The modelling identifies a portfolio of different new-build solutions that considers the contributions of the different system strength solutions at different locations to find the optimal solution to meet future minimum and efficient level requirements across the six system strength 'nodes' in NSW.

The key factors influencing the build path and market dispatch outcomes (as shown in Section 6.2) are:

Synchronous generator retirements

- The retirement of Eraring power station in August 2027 results in the additional re-dispatch of synchronous machines to meet minimum level system strength requirements, where possible, at the Sydney West, Newcastle and Armidale nodes.
- Network synchronous condensers are first available to be selected by the model from the 1st of March 2029. In addition to Eraring's retirement, the retirement of Vales Point power station in 2028/29 results in the increased re-dispatch of synchronous generators to meet minimum level requirements before network solutions are available. Coal closure induced tightness at the minimum requirements is a key factor in the build of network synchronous condensers at Kemps Creek, Newcastle and Armidale in 2028/29[49].
- Further network synchronous condenser build at Eraring and Newcastle occurs in 2029/30 to replace coal plant provision and reduce the hours of re-dispatch.
- The staged retirements of the last two Bayswater units and the Mount Piper power station in 2030/31, 2031/32, 2036/37 and 2037/28 respectively, do not directly result in the construction of new-build synchronous condensers for the minimum requirement. This is due to the synchronous condensers built prior to the retirement of the last four coal units are already sufficient to meet minimum level system strength requirements in periods with zero coal units online.

[49] In the basic portfolio, network synchronous condensers can be deployed from the 1st of March 2029. No more than three network synchronous condensers can be deployed within this financial year due to the modelled deployment assumptions of one synchronous condenser every 1.5 months which reflect the represent practical realities of deployment.

Increasing IBR capacity

- A combination of non-network GFM BESS and network synchronous condensers are constructed to meet this growing efficient level need, which increases by approximately 1,500 MVA and 3,000 MVA in 2028/29 and 2029/30 respectively.
- The initial build of IBR capacity in the CWO REZ, beginning in 2028/29, is assumed to be self-remediated by ACEREZ (as the Network Operator). As outlined in Section 4.1, synchronous condensers owned and operated by ACEREZ are deployed in 2028/29 and are sized to remediate the first 5.84 GW of IBR capacity.
- IBR capacity beyond the first 5.84 GW results in a significant amount of upgrades to grid-following ISP-modelled BESS to have GFM inverters to meet the increase in efficient level requirements, of approximately 6,000 MVA in 2028/29 and 3,300 MVA in 2029/30, respectively. The Wellington synchronous condenser deployed contributes towards meeting both the minimum and the efficient level requirements at the Wellington node.
- The build of IBR capacity in the New England REZ begins in 2032/33 and quickly increases the efficient level requirements by approximately 6,500 MVA the first year and 3,000 MVA in the next. This results in the construction of six New England REZ network synchronous condensers in 2031/32[50] and the upgrade of grid-following ISP-modelled BESS to have GFM inverters in 2032/33. A further two network synchronous condensers are built in 2032/33.

The table below provides a summary of the magnitude, location and timing of the new build synchronous condensers making up Portfolio Option 1.

Table 15. Synchronous Condensers included 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
Additional pending RFQ			Note 1				
Total Network	**-**	**3**	**9**	**9**	**9**	**9**	**9**
New England REZ	-	-	-	-	6	8	8
Note 1: If synchronous condensers with a fault level contribution of <950 MVA 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 region.							

[50] New England synchronous condensers are constructed in a 1.5 month stagger prior to commissioning date of the NE REZ Transmission Link in 2032/33 to ensure that the efficient level requirements can be met.

Portfolio Option 1 also 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 assumed for anticipated, committed and ISP-modelled BESS to upgrade to grid-forming mode from grid-following.

Table 16 presents the location (by region) and timing of grid-forming BESS in Portfolio Option 1.

Table 16. Grid-forming BESS included within Portfolio Option 1

Grid-forming BESS (MW) – Rounded to the nearest 50 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**

5.1.1 PSS®E-identified solutions to address System Strength gaps

The system strength need at Broken Hill was assessed outside the market modelling framework, as its electrically remote location could not be adequately represented. Instead, the need was evaluated in PSS®E using the Available Fault Level methodology. System strength solutions were implemented at Broken Hill and incorporated into all Portfolio Options to ensure system strength requirements are met across the broader NSW network.

5.2 Portfolio Option design

Portfolio Option 2 (‘enhanced portfolio’) was constructed to test the difference in the costs and benefits of bringing forward the procurement of synchronous condensers to add resilience to the portfolio of network synchronous condensers. The approach to Portfolio Option 2 builds on the assessment presented and consulted on in Sensitivity three of the PADR Supplementary Report.

Synchronous condensers were identified in the PADR to be a critical technology solution in 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 forecast system strength gaps. This PACR assessed three different timings for synchronous condensers, with timing reflecting latest information obtained via supplier engagement, as well as incorporation of latest forecasts of the duration of the system strength RIT-T, Contingent Project Application (CPA) and procurement processes.

The Enhanced Portfolio Option, as the preferred credible Portfolio Option, manually adjusted the earliest timing of synchronous condensers to derive three additional portfolios as shown in Figure 23 to understand the impact of different earliest synchronous condenser deployment dates. The Enhanced Portfolio Option was selected as the preferred credible option as it provided additional robustness to the power system with only a minor decrease in net market benefits of $25 million (present value terms). The quantum, timing and location of other system strength solutions were kept constant.

Figure 23. Two-phased approach to developing Portfolio Options

Objective: Identify optimal portfolio composition

Assumed synchronous condensers are first available from the earliest credible timing, 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 under 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

Objective: Assess impact of synchronous condenser timing

All options apply the location and quantum of solutions developed in the enhanced portfolio (portfolio option 2) with only the timing of synchronous condenser availability varied

Option 3: Standard Timing

Synchronous condensers available from Feb-2030

Option 4: Partial acceleration

Five accelerated synchronous condensers available from May 2028 with remaining from Feb-2030

Not currently a credible option

Option 5: Full acceleration

All accelerated synchronous condensers available from May-2028

Not currently a credible option

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, Transgrid assumed the delivery of synchronous condensers 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.

Table 17. Assumed earliest synchronous condenser deployment date in each portfolio option (i.e. date of first unit commissioned)

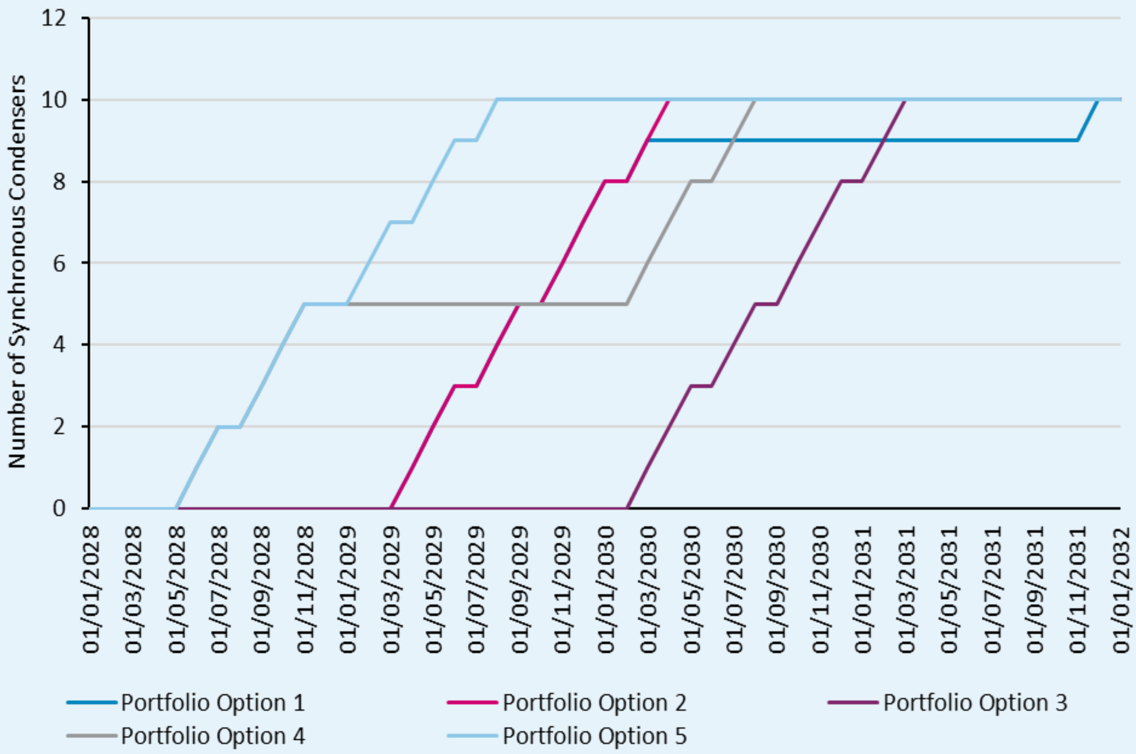
Portfolio Option	Earliest assumed timing for synchronous condenser deployment (+1.5 months for each additional required)	Justification of timing
Portfolio Option 1 and 2	March 2029	This is considered the earliest credible, yet optimistic, timing assuming fast progression through regulatory and procurement 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 determine 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.

Baringa and Transgrid assessed Portfolio Options 4 and 5 in order to identify if there are material benefits to consumers by accelerating the procurement of synchronous condensers, as was modelled in the PADR's Portfolio Option 2. These two Portfolio Options are not currently considered credible. 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. Figure 24 presents the deployment schedule of synchronous condensers in each portfolio option.

Figure 24 Deployment schedule of network (Transgrid) synchronous condensers in each portfolio option



5.3 Portfolio optimisation sensitivities

Two sensitivities were investigated to identify how the composition of the preferred Portfolio Option (Portfolio Option 2) would change if a key assumption was varied.

An overview of each sensitivity is provided below.

- **A higher 'boost' factor for grid-forming batteries;** to assess the impact of improved stable voltage waveform support from grid-forming batteries, compared to what is currently estimated by Transgrid's power system modelling.
- **Synchronous condensers costs being higher than forecast**; to assess the impact on the optimal portfolio if synchronous condenser costs are higher than forecasted.

Details of each of these sensitivities are provided in Table 18.

Table 18. Modelled portfolio composition sensitivities

Sensitivity	Assumptions
A higher 'boost factor' for grid-forming batteries	For the PACR modelling, grid-forming BESS were assigned a 'boost factor' based on the inverter supplier selected between 2.6 and 4.1. For projects without a selected supplier, a 'boost factor' of 2.6 was assumed. For this sensitivity, all grid-forming BESS being built from 2031/32 were assumed to have the maximum boost factor of 4.1, approximately a 60% increase in performance. Details on the grid-forming BESS ability to provide greater stable voltage waveform support can be found in Section 4.1.3 and Section 9.1.1 in the Transgrid PACR Meeting System Strength Report
Synchronous condensers costs being higher than forecast	For this sensitivity, we re-optimised the portfolio of system strength solutions assuming a 30% higher price for synchronous condensers (approximately), with all else being equal.

A comparison of the build paths between the basic portfolio, the higher GFM BESS Boost sensitivity and the synchronous condenser Capex sensitivity are shown in Table 19 and Table 20.

Both portfolio composition sensitivities are compared relative to the basic portfolio (Portfolio Option 1) as they were created following the portfolio optimisation methodology without the manual adjustments to synchronous condenser timing which defines Portfolio Options 2-5. Comparing the portfolio composition sensitivities to Portfolio Option 1 ensures any comparisons are done on a like-for-like basis.

The GFM boost sensitivity analysis indicates that improved performance from grid-forming BESS could reduce the number of synchronous condensers required for the New England REZ, lowering the count from 6 to 5 in 2031/32 and from 8 to 6 in 2032/33. However, synchronous condensers remain the most cost-effective option for ensuring system strength, and no change was observed in grid-forming BESS procurement by 2032/33 as shown in Table 19. A modest reduction of 300 MW in grid-forming BESS required by 2044/45 suggests enhanced BESS capability could lessen the requirement for future deployed capacity. Despite these shifts, network synchronous condensers remain essential to meeting minimum system strength requirements between 2028/29 and 2030/31.

Table 19. Comparison of portfolio composition between the basic portfolio and the GFM BESS boost portfolio[51].

Portfolio Option	2031/32	2032/33	By 2044/45
Transgrid network synchronous condensers Cumulative number of units (each providing 1,050 MVA 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 1,050 MVA 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)			
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

Table 20 identifies the changes of synchronous condenser deployment, upgrades to synchronous machines and deployment of grid-forming BESS as a sensitivity in which the cost of synchronous condensers are increased. Network (Transgrid) synchronous condensers remain unchanged in number, as their deployment is driven by minimum system strength requirements, where they continue to be one of the only viable solutions. At Dinawan, manual modelling assessment confirms that even with higher capital costs, synchronous condensers are more cost-effective per MVA compared to grid-forming BESS, preserving their role in meeting system needs. However, for the New England REZ, the increased cost of synchronous condensers shifts the balance by 2032/33, making grid-forming BESS the more economical option and removing the need for the synchronous condenser in 2032/33. This shift is enabled by an additional 1.15 GW of grid-forming BESS, which meets both efficient and minimum level requirements from 2032/33 onward.

Table 20. Comparison of portfolio composition between the basic portfolio and the higher synchronous condenser cost sensitivity

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 1,050 MVA fault current)							
Portfolio Option 1: Basic portfolio	-	3	9	9	9	9	9

[51] All MW values in Table 19 are rounded to the nearest 50 MW.

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

6 Market dispatch outcomes

The results from the PACR market dispatch modelling are presented in Sections 6 and 7 of the PACR. This section provides additional detail, presenting market dispatch modelling outcomes beyond those presented in the PACR report. In this section:

- Section 6.1 provides an overview of the Base Case market dispatch outcomes, which represents a ‘do nothing’ counterfactual, against which to compare the costs and benefits of each Portfolio Option; and
- Section 6.2 provides the re-dispatch outcomes from the half-hourly modelling for each Portfolio Option.

6.1 Base Case

The ‘Base Case’ provides a counterfactual against which to compare the impact of the system strength Portfolio Options. Consistent with the RIT-T requirements, the assessment undertaken in the PACR compares the costs and benefits of each Portfolio Option with a ‘do nothing’ Base Case. The Base Case is the (hypothetical) projected case if no action is taken, i.e:

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. [52]

Within Baringa’s market dispatch optimisation, the Base Case seeks to meet system strength constraints, balance supply and demand and minimise total system cost following the methodology outlined in Section 2.5.2 – but does this under the assumption that no new system strength solutions are built.

As such, only committed and anticipated projects that are considered as potential system strength solutions are available to meet system strength requirements. Existing, committed and anticipated projects (primarily existing synchronous machines) are therefore ‘re-dispatched’ significantly to attempt to meet the growing requirement for system strength, until the requirement exceeds feasible supply as the efficient levels increase and synchronous coal generators progressively retire.

Without new build system strength solutions available to meet the growing need for system strength, the following situations could arise:

- constraints in system operation would occur to minimise gaps in system strength (e.g. limitations to transmission network outage programmes, avoidance of generator maintenance where possible);
- existing and committed synchronous generators would be directed to operate (to raise the level of system strength in the system);

[52] AER, Regulatory Investment Test for Transmission Application Guidelines, October 2023, p. 22. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

- renewable generation would be constrained (as synchronous generation retires and the power system is increasingly reliant on IBR, this could lead to insufficient generation and ultimately unserved energy);
- and system strength would continue to progressively decrease. If system strength levels fell below minimum level requirements, protection systems may not operate correctly, and the power system may be unable to remain stable following a contingency event. This could lead to cascading failures in the transmission network and, in the worst case, widespread and extensive power outages including involuntary load curtailment.

While Transgrid's NER obligations and this RIT-T have been initiated specifically to avoid system strength gaps, the assessment is required under the RIT-T to consider this Base Case as a common point of reference when estimating the net benefits of each credible option. Transgrid does not intend to let power system security decline in this way and as such, we have used only pragmatic assumptions to model the situation above.

6.2 Portfolio Option dispatch results

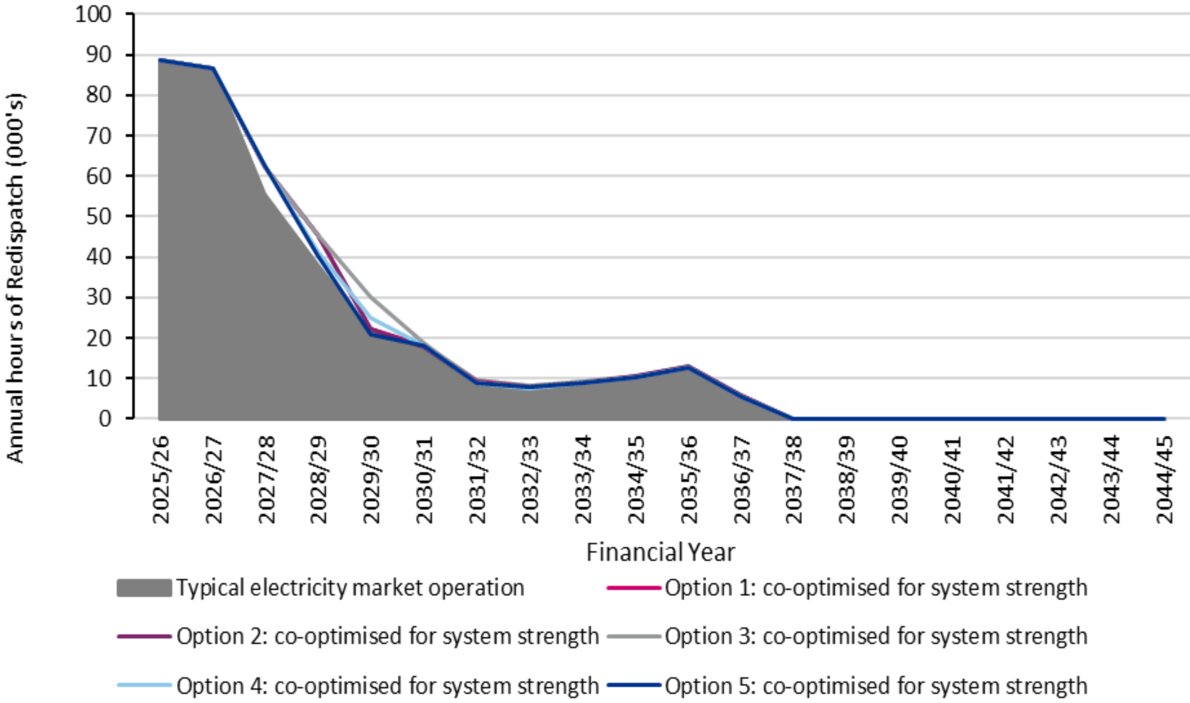
Synchronous machines are a significant source of system strength provision within NSW. Re-dispatch accounts for the increased operation of synchronous machines above the modelled operation from typical electricity market operation as part of the least-cost dispatch solution.

The market dispatch outcomes shown below are a result of the co-optimised system strength and energy market modelling model as outlined in Section 2.5.2.[53] This market modelling phase occurs at half-hourly granularity and does not consider capacity expansion decisions. Planned maintenance buffers of new-build synchronous condensers are incorporated into the RHS of the system strength requirements alongside the other features detailed in Section 4.2.

[53] Re-dispatch for 2025/26 and 2026/27 have been calculated and presented using Transgrid's system security limits advice and is identical across all portfolio options. 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).

6.2.1 NSW Coal Re-dispatch

Figure 25. Re-dispatch of NSW Coal across modelled Portfolio Options

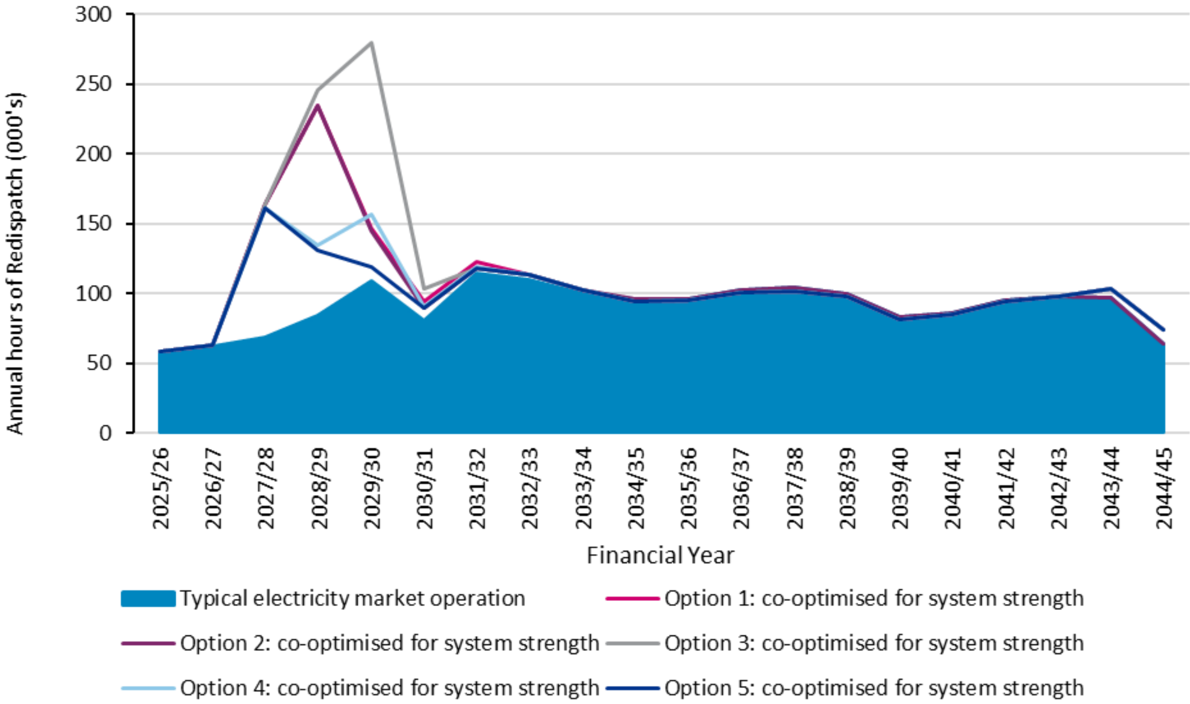


Coal re-dispatch is identical across all portfolio options for the first two years of the horizon, 2025/26 and 2026/27. This is due to the lack of build candidates capable of contributing to minimum fault levels at this stage of the horizon. Between 2027/28 and 2030/31, the accelerated network synchronous condenser deployment schedules of Portfolio Option 4 and 5 decrease the amount of coal re-dispatch required relative to Portfolio Options 1, 2 & 3. In 2029/30 the delayed deployment of network synchronous condensers of Portfolio Option 3 results in 8,848 hours of re-dispatch above that from normal wholesale market dispatch.

The re-dispatch of coal in NSW falls to zero in 2031/32 as the final network synchronous condensers of Portfolio Option 1 are deployed. GFM BESS begin to contribute to minimum level requirements from 2032/33 and further reduce the need for the redispatch of NSW coal units. The provision of system strength from NSW coal units as a byproduct of wholesale market dispatch still contributes to meeting the minimum and efficient level requirements as a byproduct of energy dispatch the retirement of the last NSW coal unit in 2037/38.

6.2.2 NSW Hydro and PHES Re-dispatch

Figure 26. Re-dispatch of NSW hydro and PHES across modelled Portfolio Options



The re-dispatch of hydro and PHES units includes units re-dispatched to generate, pump and, for those plant which have the capability to do so, operate in synchronous condenser mode.

Hydro units (included pumped hydro storage) have a lower operational cost to synchronise to the grid than typical thermal such as coal and gas. As the model aims to maximise the market and consumer benefits, it chooses to re-dispatch hydro as a lower cost to provision technology first than the thermal assets. The different Portfolio Options demonstrate a large variance of hydro operational hours as it is the first chosen synchronous technology to re-dispatch based on an economic basis, particularly in the years before network solutions become readily available.

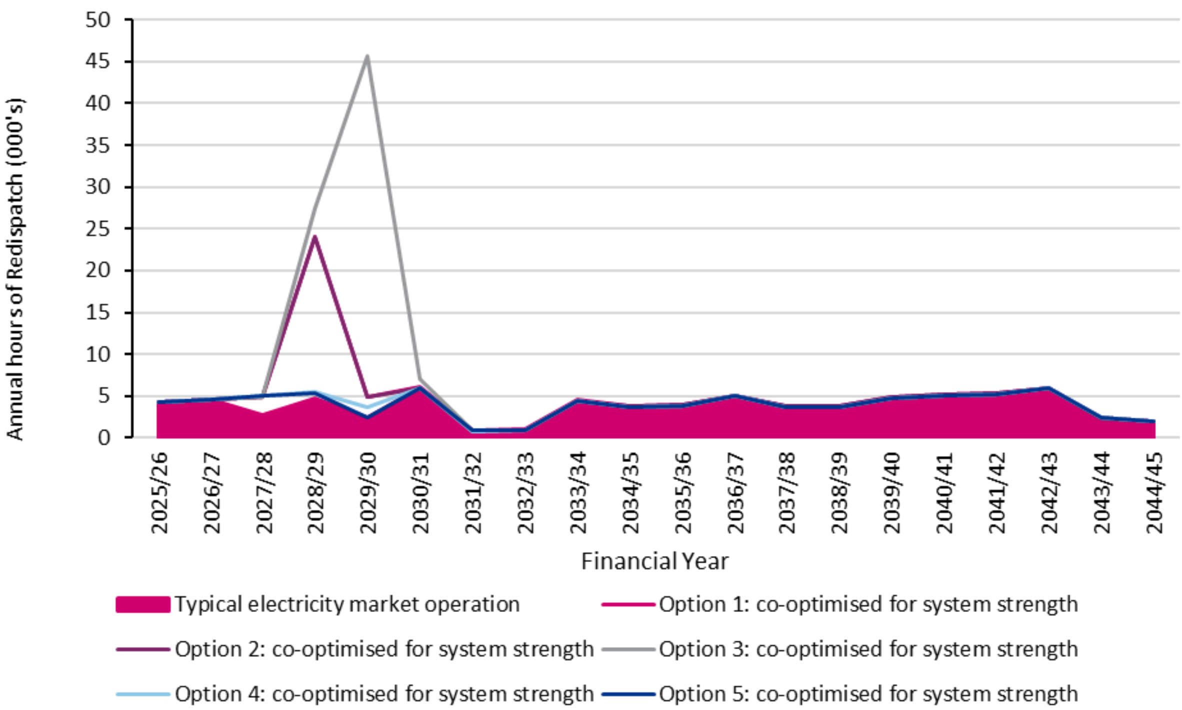
Once again, Portfolio Option 3 has the greatest amount of required re-dispatch due to the later network synchronous condenser commissioning dates. Portfolio Option 1 and Portfolio Option 2 have identical re-dispatch paths until 2029/30 and have the greatest difference in 2030/31 where the additional synchronous condenser under the enhanced portfolio decreases the hydro re-dispatch by approximately 4,000 hours relative to Portfolio Option 1.

The operation of hydro and PHES units across all Portfolio Options closely follows the wholesale market outcomes from 2033/34 to 2042/43. Consequently, the majority of system strength provision from hydro and PHES units post 2033/34 is a byproduct of energy dispatch. In the last two years of the horizon, 2043/44 and 2044/45, an increase in the Darlington Point efficient level requirement results in an increase in the re-dispatch of hydro & PHES as the least-cost method of meeting the increased requirement.

The re-dispatch of hydro and PHES units under Portfolio Options 4 & 5 are the two lowest of the modelled portfolios. Portfolio Option 5's additional accelerated synchronous condensers result in approximately 37,000 fewer hours of re-dispatch in 2029/30 – the year in which the build paths of these portfolios differ the most.

6.2.3 NSW Gas Re-dispatch

Figure 27. Re-dispatch of NSW gas plant across modelled Portfolio Options



Gas plant re-dispatch primarily occurs in 2027/28, 2028/29 and 2029/30. As the category with the highest short run marginal cost of generation, gas plants are typically dispatched to meet system strength gaps behind other forms of synchronous machines.

Portfolio Options 1 and 2 have approximately 19,000 hours of re-dispatch in 2028/29 with Portfolio Option 3 having approximately 22,700 hours in the same year. The delayed synchronous condenser timing associated with Portfolio Option 3 results in greater re-dispatch of gas plant to meet system strength requirements. In 2029/30 the gas re-dispatch of Portfolio Option 3 is approximately 41,000 hours greater than the nearest Portfolio Option, Portfolio Option 1. Portfolio Options 4 and 5 have lower gas re-dispatch past 2027/28 due to the accelerated network synchronous condenser deployment schedule.

From 2031/32 gas re-dispatch is not required as sufficient new-build system strength solutions are operational.

7 Market benefit outcomes

The PACR presents analysis of the net economic benefits delivered by each of the Portfolio Options. This section provides additional detail behind the net present value results by showing the annual costs and benefits of the preferred Portfolio Option relative to Portfolio Option 1, Portfolio Option 3 and the Base Case[54]. Portfolio Options 4 and 5, as the two non-credible Portfolio Options, are compared with respect to each other in Figure 33 as the two non-credible options.

Figure 28, reproduced from the PACR, depicts a high-level summary of the net present value of the net economic benefits of each Portfolio Option. 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.

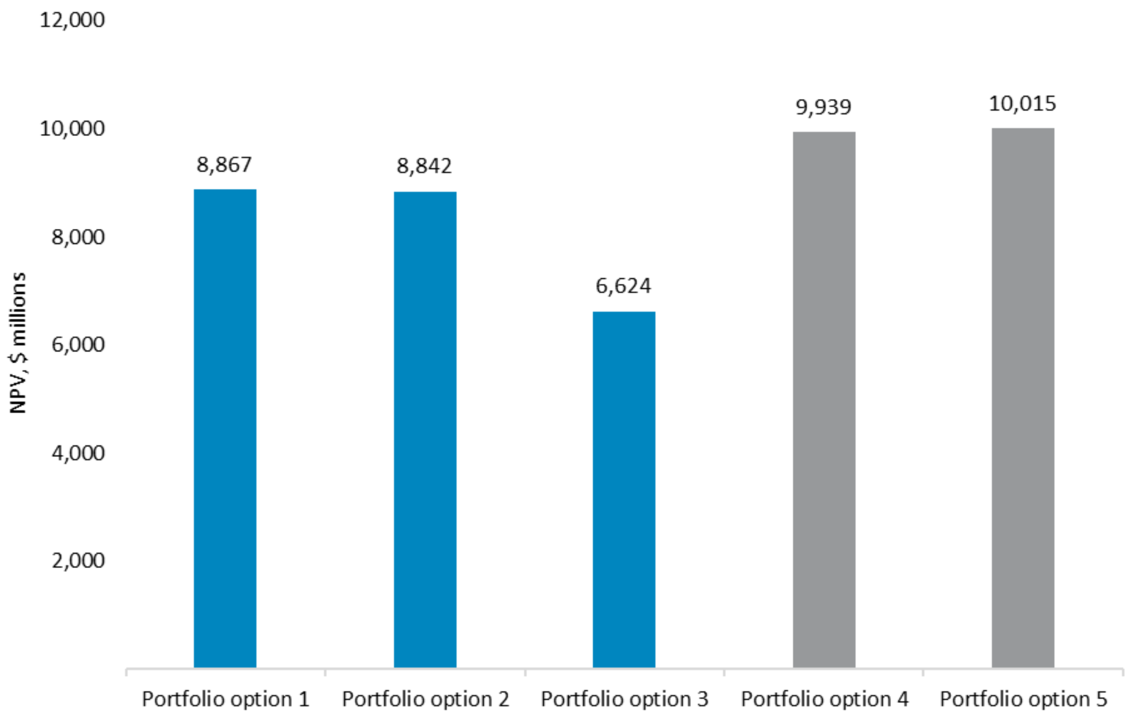
The analysis finds that the later entry of synchronous condensers in Portfolio Option 3 (i.e. from February 2030) results in a present value $2.2 billion reduction in net market benefits against Portfolio Option 2 which applies earlier synchronous condenser timing (i.e. from March 2029). The substantial reduction in net market benefits for Portfolio Option 3 is primarily driven by Portfolio Option 2's greater avoided involuntary load curtailment via system strength gaps. This occurs due to the earlier availability of network system strength solutions.

The analysis finds that 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), 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).

The substantial benefits these accelerated Portfolio Options bring is primarily in avoiding risks of system strength gaps compared to Portfolio Options 2 and 3 (leading to involuntary load curtailment), 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 from earlier expenditure upon synchronous condensers.

54 Portfolio Options 4 and 5 are not considered in this analysis as they are currently not considered credible.

Figure 28. Net present value of net market benefits for the Portfolio Options.[55]



7.1 Gross market benefits comparison

Figure 29 shows the economic costs and benefits for Portfolio Option 2 relative to the Base Case, separated by market benefit categories. Negative values represent a relative market benefit of the Base Case through avoided costs, i.e. in this context costs incurred in Portfolio Option 2 but not within the Base Case. Positive values depict the opposite and depict the market benefits of Portfolio Option 2 relative to the Base Case[56]. All values for the remainder of this section are undiscounted in real 2023/24 dollars.

While Transgrid's NER obligations and this RIT-T have been initiated specifically to avoid system strength gaps, the Base Case provides an insightful counterfactual to the market benefits of the modelled Portfolio Options. Costs attributable to involuntary load curtailment via system strength gaps are presented separately in Figure 30 as the benefits from this category are so large that, if they were to be presented in Figure 29, it would be difficult to interpret the other benefits classes.

The annual Capex and Opex values presented in this section exclude costs associated with synchronous condenser mode upgrades and committed and anticipated batteries due to confidentiality.

[55] Headline, discounted NPV results for Portfolio Option 1 – 5; blue indicates currently credible Portfolio Options; grey indicates a Portfolio Option that is not yet credible but would deliver additional market benefits to consumers.
[56] Where benefits reflect costs incurred by the Base Case which are not incurred within the Portfolio Option 2.

7.1.1 Portfolio Option 2 relative to the Base Case

Figure 29. Differences in market benefits classes between Portfolio Option 2 and the Base Case (excluding value attributable to avoided involuntary load curtailment)

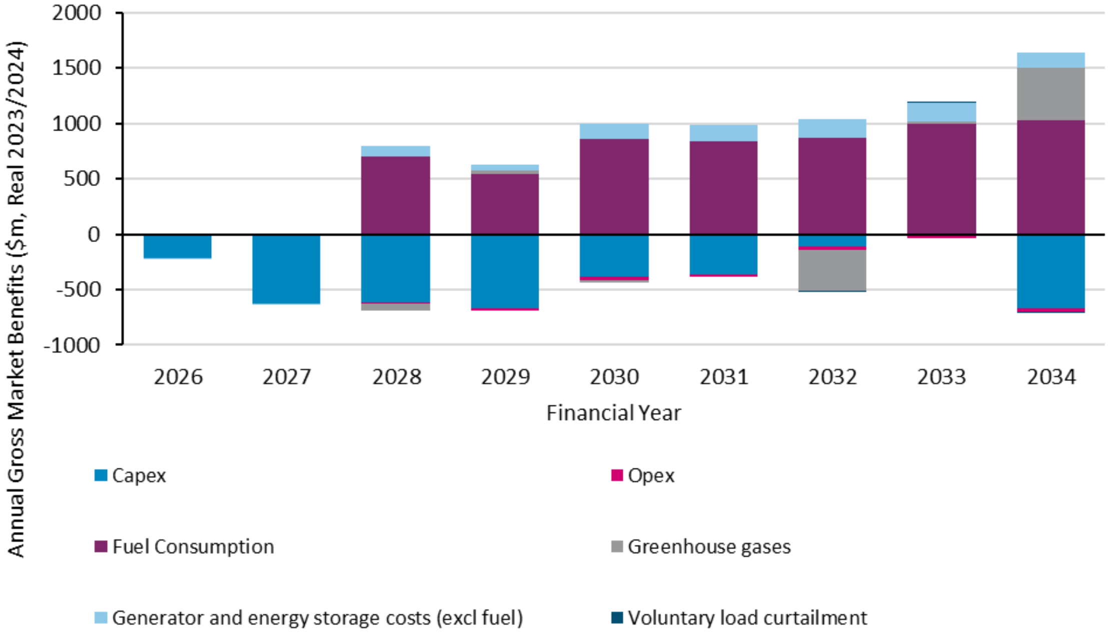
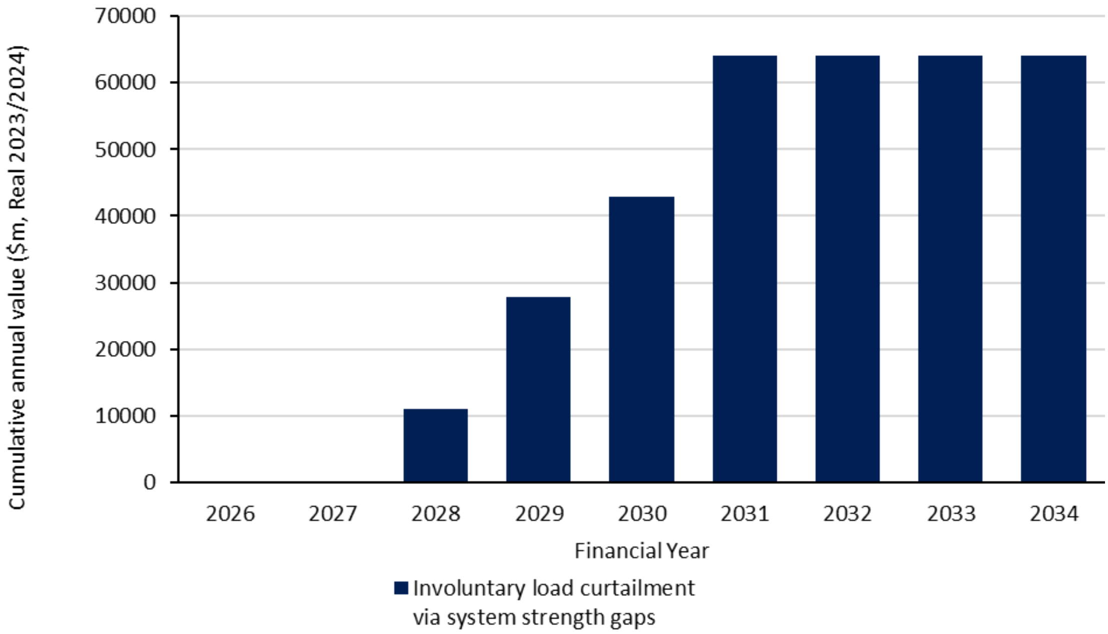


Figure 30. Cumulative differences in avoided involuntary load curtailment via system strength gaps between Portfolio Option 2 and the Base Case to 2033/34



The Base Case, by design, has no costs associated with the Capex and Opex of new-build system strength solutions. Consequently, Portfolio Option 2 has greater Capex and Opex across the entirety of the modelled horizon. Capex costs over the first two years of the horizon are increased by the realisation of synchronous condenser expenditure occurring over the three years prior to its deployment.

Compared to the Base Case, Portfolio Option 2 sees significantly greater market benefits from 2028/29 due to:

- lower costs associated with involuntary load curtailment due to fewer gaps in system strength requirements;
- lower fuel costs and emissions costs driven by reduced running hours for coal and gas; and
- lower generator and energy storage costs due to reduced variable operational costs of hydro, PHES, coal and gas units.

As a consequence of the pragmatic assumptions to model the Base Case, in some years, costs from greenhouse gas emissions are greater under Portfolio Option 2 than in the Base Case. The cost of emissions does not form part of the least-cost optimisation within PLEXOS with the calculation of greenhouse gas emissions costs performed outside of the market modelling phase as per AER guidelines.[57]

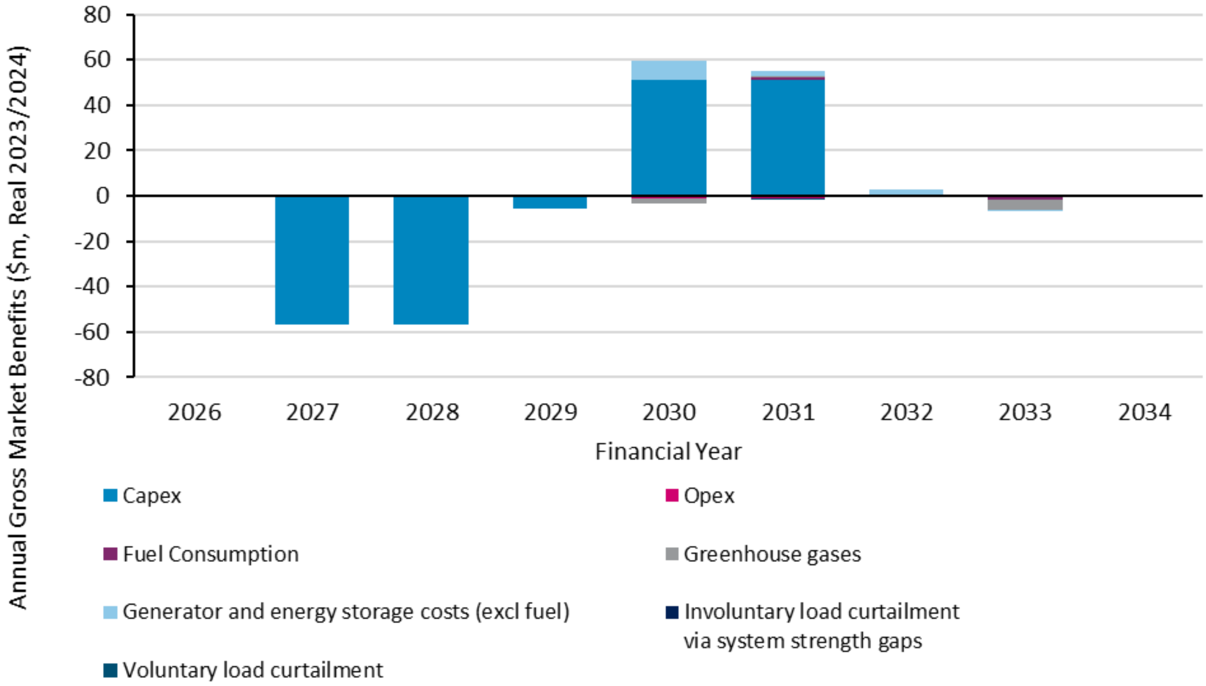
Market benefits associated with avoided fuel costs and avoided greenhouse gas emissions relative to the Base Case are a predominant feature of all modelled Portfolio Options and sensitivities. New system strength solutions (synchronous condensers and grid-forming batteries) reduce the operational reliance upon synchronous thermal generators for system strength purposes.

The remaining market benefits categories of involuntary load curtailment and voluntary load curtailment are not material.

[57] AER, Regulatory Investment Test for Transmission Application Guidelines, October 2023, p. 22. Available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

7.1.2 Portfolio Option 2 relative to Portfolio Option 1

Figure 31. Differences in market benefit classes between Portfolio Option 2 and Portfolio Option 1

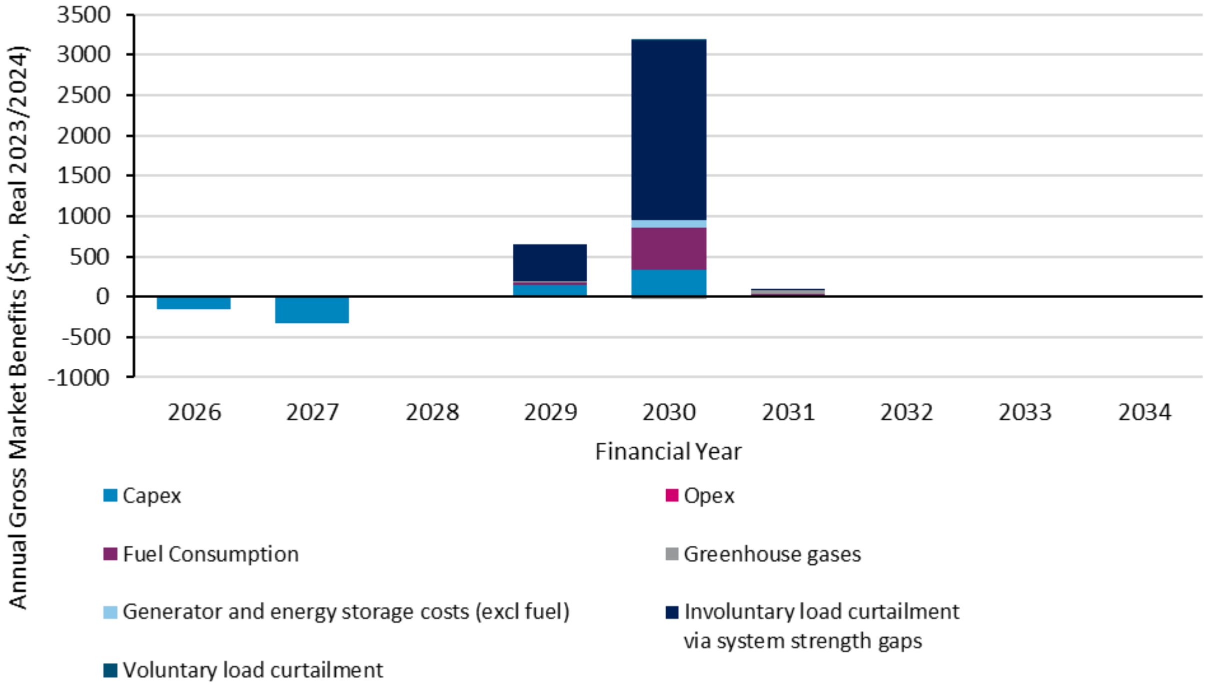


Additional capex (blue) on new build system strength solutions is the main driver of additional cost under Portfolio Option 2 relative to Portfolio Option 1. In the calculation of market benefits, capex on new build synchronous condensers is incurred as equal cash flows over the three years prior to the solution's commissioning. The earlier commissioning of one synchronous condenser under Portfolio Option 2 results in earlier capex expenditure compared to Portfolio Option 1.

Costs associated with fuel consumption, greenhouse gas emissions, voluntary load curtailment and generator and energy storage costs (excluding fuel consumption) are relatively consistent between the two Portfolio Options throughout the modelled horizon, and do not significantly affect the net economic benefits assessments of the enhanced portfolio relative to the basic portfolio.

7.1.3 Portfolio Option 2 relative to Portfolio Option 3

Figure 32. Differences in market benefits classes between Portfolio Option 2 and Portfolio Option 3

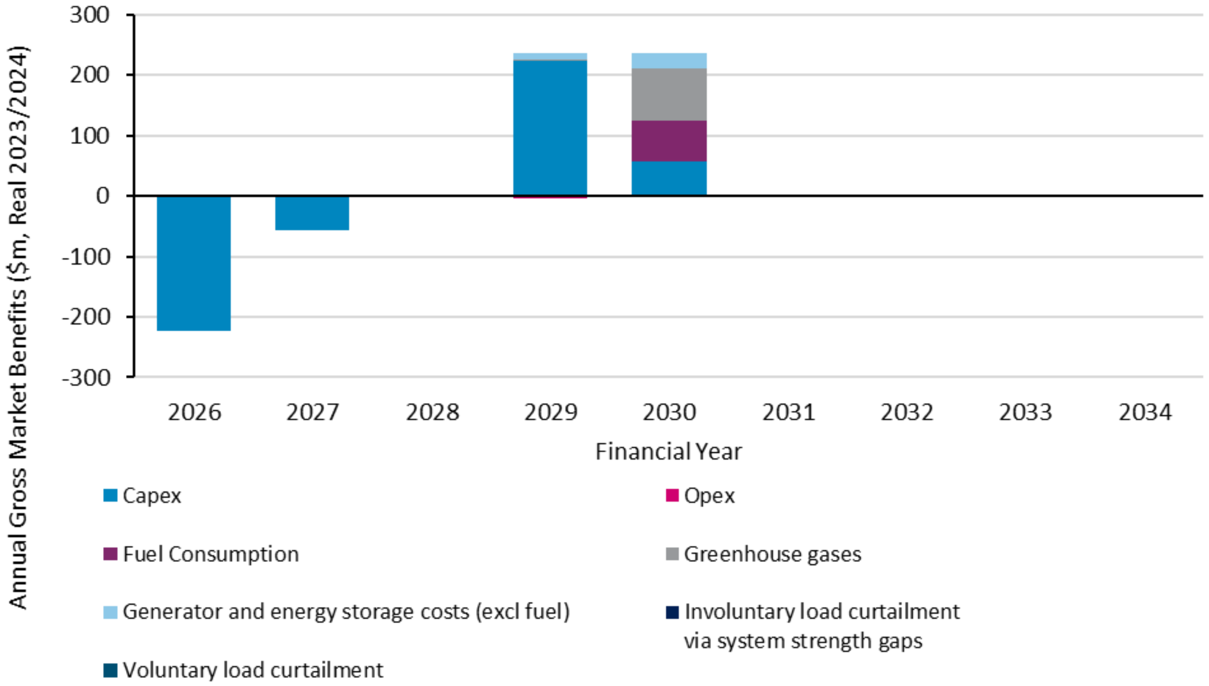


The market benefits for Portfolio Option 2 most significantly diverge from Portfolio Option 3 in 2029/2030. The earlier deployment of non-network options in portfolio 2 prevents the system strength gaps in 2029/30 which are present for Portfolio Option 3.

The early capex savings in 2025/26 and 2026/27 from Portfolio Option 3's delayed synchronous condenser build are far outweighed by the costs from system strength gaps, fuel consumption and generator and energy storage costs. The build paths of system strength solutions between the two portfolios converge in 2030/31 resulting in identical market benefits outcomes from 2031/32 onwards.

7.1.4 Portfolio Option 5 relative to Portfolio Option 4

Figure 33. Differences in market benefit classes between Portfolio Option 5 and Portfolio Option 4



Portfolio Option 4 and Portfolio Option 5 are defined by their acceleration of synchronous condensers delivered in 2027/28 and 2028/29. Where Portfolio Option 5 assumes the accelerated deployment of all ten network synchronous condensers, Portfolio Option 4 assumes the accelerated deployment of five. Consequently, there is a delay of 16 months between the deployment of the fifth synchronous condenser at Darlington Point and the sixth at Kemps Creek in Portfolio Option 4. The additional cost associated with fuel consumption, greenhouse gas emissions and generator and energy storage costs in 2029/30 are because of the different synchronous condenser build paths. Portfolio Option 5 has 10 synchronous condensers operational at the start of 2029/30 whereas Portfolio Option 4 only has 5.

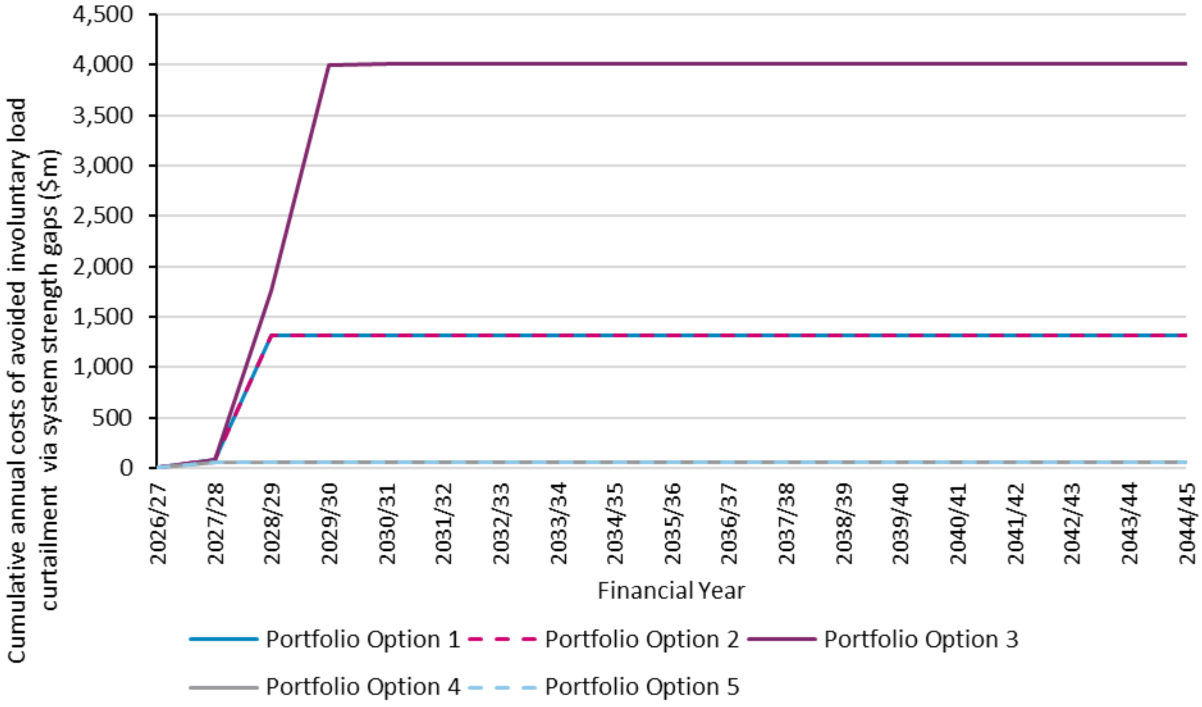
From 2031/32, differences in market benefits between the two Portfolio Options converge as the synchronous condenser build paths are identical.

7.2 Involuntary load curtailment due to system strength gaps

Within this RIT-T assessment, only the differences in avoided unserved energy across the portfolio options are valued. This is achieved by explicitly removing 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. Baringa and 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[58].

The cost of involuntary load curtailment via system strength gaps varies between the different Portfolio Options, with the main divergence occurring in 2028/29, as visible in Figure 34.

Figure 34. Undiscounted, cumulative cost of involuntary load curtailment via system strength gaps



Portfolio Option 1 and Portfolio Option 2 have values of avoided involuntary load curtailment in both 2027/28 and 2028/29 at $79.7m and $1,311m respectively. The additional robustness associated with Portfolio Option 2 does not directly result in reduced system strength gaps but rather reduced fuel consumption, generator and energy storage costs and emissions costs as demonstrated in Figure 31 above.

[58] Biggar, D., May 2017, An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program

The specific approach adopted to removing the common avoided involuntary load curtailment has been to only include the avoided involuntary load curtailment 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 PACR has zero avoided involuntary load curtailment for Portfolio Option 3, and a positive amount for the other Portfolio Options.

Portfolio Option 4 and 5 have the greatest amount of avoided involuntary load curtailment via system strength gaps. This is due to the accelerated deployment of five synchronous condensers in both Portfolio Option 4 and Portfolio Option 5. These accelerated synchronous condensers remove the risk of system strength gaps in in 2028/29 for Portfolio Options 1 and 2 and both 2028/29 and 2029/30 for Portfolio Option 3.

Following the 2028/29 financial year, there is minimal involuntary load curtailment via system strength gaps across all Portfolio Options except Portfolio Option 3 as there are sufficient new-build system strength solutions which can be deployed to meet the need.

Appendix A Additional results

A.1 Net present value of market benefit classes

Figure 35. Differences in market benefit classes between Portfolio Option 2 and Portfolio Option 1

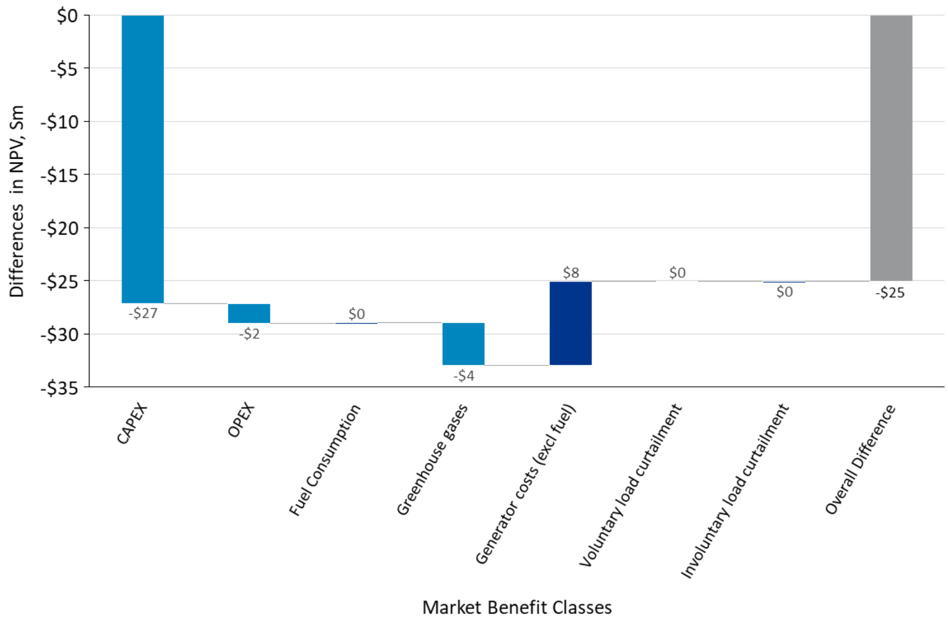


Figure 36. Differences in market benefit classes between Portfolio Option 2 and Portfolio Option 3

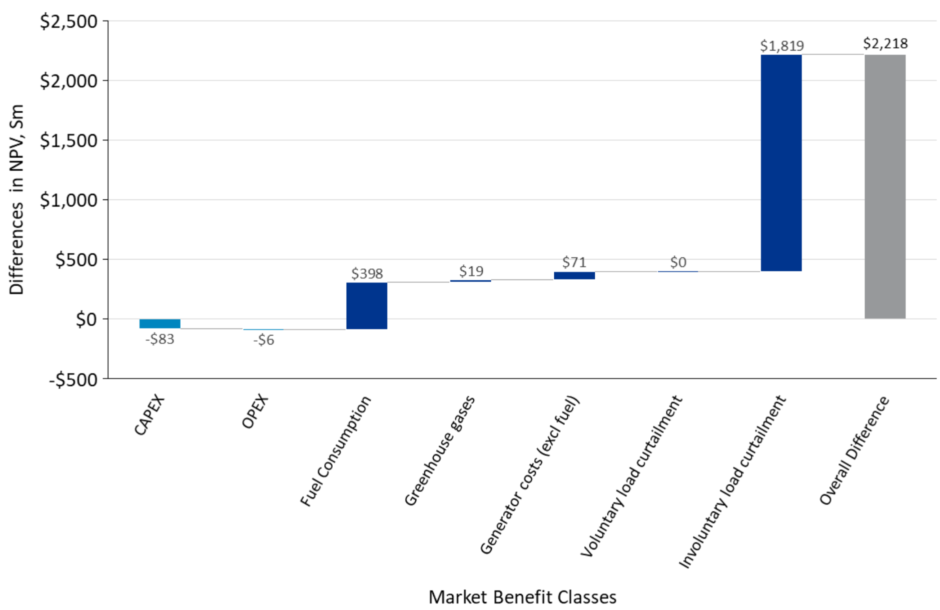


Figure 37. Differences in market benefit classes between Portfolio Option 4 and Portfolio Option 2

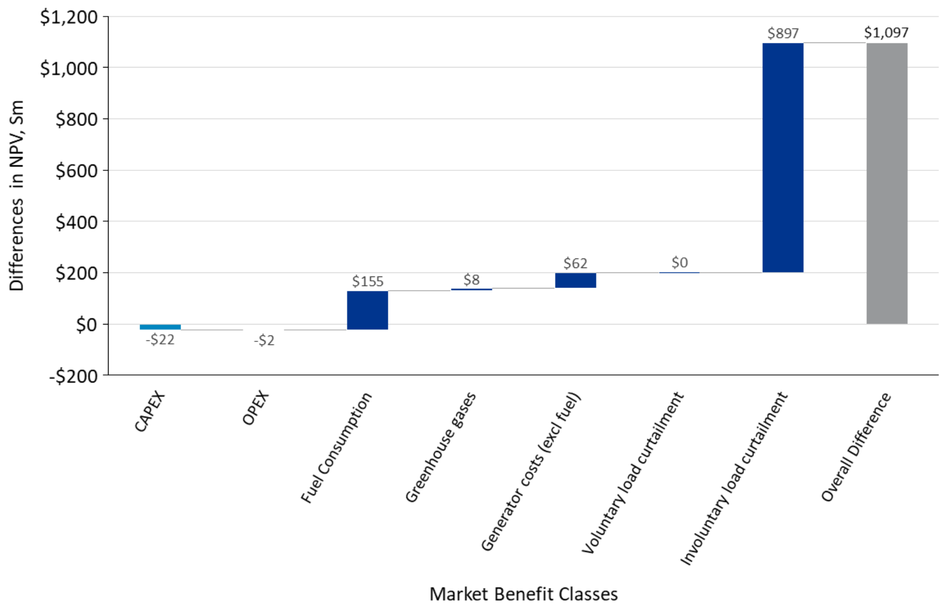


Figure 38. Differences in market benefit classes between Portfolio Option 5 and Portfolio Option 2

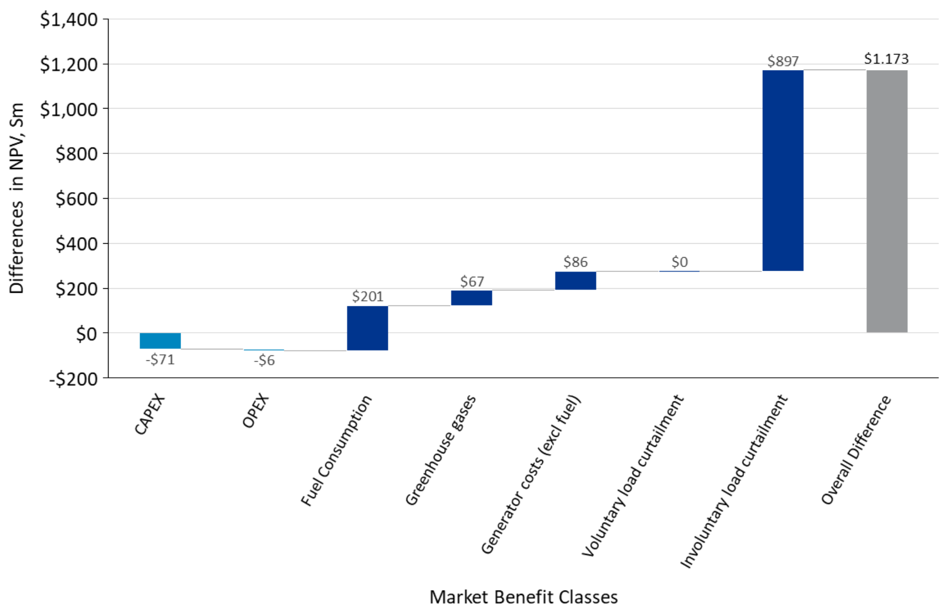
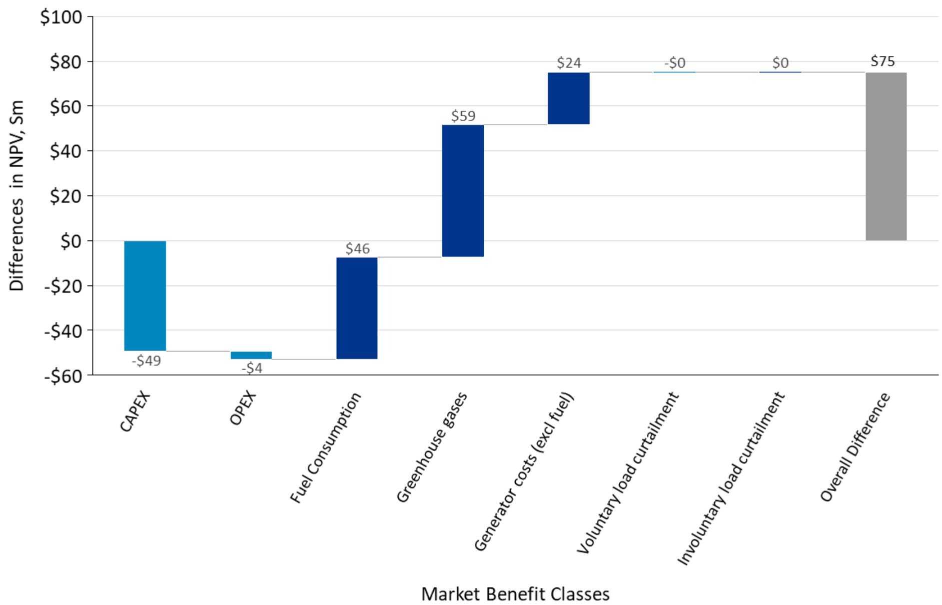


Figure 39. Differences in market benefit classes between Portfolio Option 5 and Portfolio Option 4



Appendix B Glossary

Term	Definition
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
BAU	Business-as-Usual
BESS	Battery energy storage system
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CPA	Contingent Project Application
DER	Distributed Energy Resources
EMT	Electromagnetic Transient
EOI	Expression of Interest
FACTS	Flexible AC Transmission System
GW	Gigawatt
GFL	Grid-following Inverter Technology
GFM	Grid-forming Inverter Technology
IBR	Inverter Based Resource
IASR 2023	2023 Inputs, Assumptions and Scenarios Report published by AEMO
ISP	Integrated System Plan
LHS	Left Hand Side
MNSP	Market Network Service Provider
MVA	Megavolt-ampere.
MW	Megawatt
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NIS	Network Infrastructure Strategy
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
ODP	Optimal Development Pathway
OEM	Original Equipment Manufacturer
PACR	Project Assessment Conclusion Report

PADR	Project Assessment Draft Report
PSCAD™	Power System Computer Aided Simulation.
PSCR	Project Specification Consultation Report
PHES	Pumped Hydroelectric Energy Storage
PSS®E	Power System Simulator for Engineering.
QLD	Queensland
QNI	Queensland - New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QEJP	Queensland Energy and Jobs Plan
REZ	Renewable Energy Zone
RHS	Right Hand Side
RIT-T	Regulatory Investment Test for Transmission
RMS	Root Mean Square
SA	South Australia
Snowy 2.0	Snowy 2.0 Pumped Storage Power Station
SCR	Short Circuit Ratio
SRMC	Short-Run marginal Cost
SSIAG	System Strength Impact Assessment Guidelines
SSSP	System Strength Service Provider
SSMR	System Strength Mitigation Requirement
STATCOM	Static Synchronous Compensator.
TAS	Tasmania
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer reliability
VIC	Victoria
VNI	Victoria - New South Wales Interconnector
VRET	Victoria Renewable Energy Target
WACC	Weighted Average Cost of Capital